MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") provides a review of the operations, financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the three and nine months ended September 30, 2024 and 2023. This MD&A is dated as at October 30, 2024 and should be read in conjunction with the unaudited condensed interim consolidated financial statements for the three and nine months ended September 30, 2024 and 2023 ("Interim Financial Statements") and the audited consolidated financial statements for the year ended December 31, 2023. Additional information relating to Tamarack, including the Company's Annual Information Form for the year ended December 31, 2023, is available on SEDAR+ at www.sedarplus.ca and Tamarack's website at www.tamarackvalley.ca.

The Company uses certain Non-GAAP Financial Measures, Non-GAAP Financial Ratios, Capital Management Measures and Capital Management Ratios in this MD&A. Certain Supplemental Financial Measures are also presented on a per boe, per share or on a percentage basis. For additional information regarding these measures, refer to the "Advisories and guidance" section of this MD&A. Unless otherwise indicated, all references to dollar amounts are in Canadian ("CAD") currency.

About Tamarack Valley Energy Ltd.

Tamarack is a corporation engaged in the exploration, development, production and sale of oil and natural gas in the Western Canadian Sedimentary Basin. The Company is currently developing two core projects in Northern Alberta – a Clearwater heavy oil position at Nipisi, Marten Hills and South Clearwater and a Charlie Lake light oil position at Valhalla, Wembley and Pipestone. Tamarack also manages an EOR portfolio of diverse assets across Alberta.

As of December 31, 2023, the Company held over 650 sections of acreage across the Clearwater fairway with 112.5 million boe of total gross proved plus probable reserves[1]. The Clearwater formations are characterized by strong economics supported by a low cost structure, low production declines and multiple payouts on initial investment. The formation also has enhanced recovery potential. Tamarack produced over 40,000 boe per day of heavy oil and natural gas (93% liquids) from the Clearwater in the first nine months of 2024.

Tamarack holds over 250 sections of Charlie Lake acreage with 67.4 million boe of total gross proved plus probable reserves[1] providing the Company with extensive light oil development opportunities through multi-well pad drilling with extended horizontal reach. The Charlie Lake formations are characterized by short payout periods and low break-even economics. The Company produced over 15,000 boe per day of oil and natural gas (67% liquids) from Charlie Lake in the first nine months of 2024.

Tamarack has 103 employees at the corporate head office and seven employees at field level operations. The Company is incorporated and domiciled in Alberta, Canada with the head office located at Suite 1700, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1. Tamarack is a publicly traded company on the Toronto Stock Exchange ("TSX") and is traded under the symbol "TVE".

Q3 2024 in review

Tamarack has delivered strong third quarter results generating production of 65,024 boe per day, adjusted funds flow[2] of $220.4 million and free funds flow[2] of $108.7 million. On September 17th, the Company expanded the Clearwater Infrastructure Partnership by adding a 13th Indigenous Community to the arrangement through the contribution of additional Clearwater infrastructure assets, receiving cash proceeds of $43.2 million. During the third quarter, Tamarack reduced net debt[2] by $75.3 million and delivered $69.9 million to shareholders through a combination of dividends and share buybacks. Margins have continued to improve with improved price realizations and lower lifting costs. Strong production results, ongoing capital efficiencies and a portion of the proceeds from the Clearwater Infrastructure Partnership transaction have allowed Tamarack to execute previously announced capital investments for growth activities in the Charlie Lake area in advance of the third-party CSV Albright plant commissioning in early 2025, within the Company's original capital budget guidance range.

(1) Based upon the independent reserves evaluations conducted by McDaniel & Associates Consultants Ltd. ("McDaniel") and GLJ Ltd. ("GLJ"), as at December 31, 2023. Refer to "Advisories and guidance" for additional information about the independent reserves evaluations conducted by McDaniel and GLJ.

(2) Refer to "Advisories and guidance" for more information on Capital Management Measures and Ratios, Non-GAAP Financial Measures and Ratios and Supplemental Financial Measures.

Q3 2024 operational and financial highlights

	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
($ thousands, except per share amounts)						
Oil and natural gas sales, before blending	**$ 439,435**	$ 506,365	(13)	**$ 1,294,250**	$ 1,284,066	1
Cash provided by operating activities	**240,843**	199,756	21	**631,414**	415,645	52
Per share – basic[1]	**0.45**	0.36	25	**1.15**	0.75	53
Per share – diluted[1]	**0.44**	0.36	22	**1.15**	0.74	55
Adjusted funds flow[1]	**220,419**	255,199	(14)	**627,529**	569,723	10
Per share – basic[1]	**0.41**	0.46	(11)	**1.15**	1.02	13
Per share – diluted[1]	**0.40**	0.46	(13)	**1.14**	1.02	12
Free funds flow[1]	**108,688**	128,857	(16)	**297,693**	176,203	69
Per share – basic[1]	**0.20**	0.23	(13)	**0.54**	0.32	72
Per share – diluted[1]	**0.20**	0.23	(14)	**0.54**	0.31	72
Net income	**93,694**	8,634	985	**155,837**	36,874	323
Per share – basic	**0.17**	0.02	750	**0.28**	0.07	300
Per share – diluted	**0.17**	0.02	750	**0.28**	0.07	300
Net debt[1]	**807,401**	1,128,030	(28)	**807,401**	1,128,030	(28)
Investments in oil and natural gas assets	**109,032**	122,759	(11)	**323,594**	388,752	(17)
Weighted average shares outstanding						
Basic	**540,990**	556,708	(3)	**547,074**	556,399	(2)
Diluted	**545,266**	558,569	(2)	**551,091**	559,958	(2)
Average daily production						
Heavy oil (bbls/d)	**39,047**	35,900	9	**37,659**	35,229	7
Light oil (bbls/d)	**13,203**	16,974	(22)	**14,422**	16,797	(14)
NGL (bbls/d)	**2,915**	3,623	(20)	**2,460**	3,795	(35)
Natural gas (mcf/d)	**59,154**	72,597	(19)	**55,162**	71,633	(23)
Total (boe/d)	**65,024**	68,597	(5)	**63,735**	67,760	(6)
Average sale prices						
Heavy oil, net of blending expense ($/bbl)[1]	**$ 85.25**	$ 92.85	(8)	**$ 83.19**	$ 76.15	9
Light oil ($/bbl)	**97.79**	107.83	(9)	**96.71**	98.30	(2)
NGL ($/bbl)	**39.58**	41.46	(5)	**39.32**	41.51	(5)
Natural gas ($/mcf)	**0.87**	2.60	(66)	**1.72**	2.84	(39)
Total ($/boe)	**73.62**	80.22	(8)	**74.05**	69.29	7
Benchmark pricing						
West Texas Intermediate (US$/bbl)	**75.09**	82.26	(9)	**77.54**	77.39	0
Western Canadian Select (WCS) (C$/bbl)	**83.95**	93.09	(10)	**84.45**	80.38	5
WCS differential (US$/bbl)	**13.55**	12.88	5	**15.49**	17.63	(12)
Edmonton Par (Cdn$/bbl)	**97.85**	107.90	(9)	**98.43**	100.63	(2)
Edmonton Par differential (US$/bbl)	**3.35**	1.85	81	**5.21**	2.61	100
Foreign Exchange (USD to CAD)	**1.36**	1.34	1	**1.36**	1.35	1
Operating netback ($/Boe)						
Realized sales price, net of blending[1]	**73.62**	80.22	(8)	**74.05**	69.29	7
Royalty expenses	**(15.74)**	(13.38)	18	**(14.65)**	(12.70)	15
Net production expenses[1]	**(8.62)**	(8.47)	2	**(9.12)**	(9.72)	(6)
Transportation expenses	**(2.36)**	(4.13)	(43)	**(3.47)**	(4.00)	(13)
Carbon tax	**(0.08)**	-	nm	**(0.40)**	-	nm
Operating field netback ($/Boe)[1]	**46.82**	54.24	(14)	**46.41**	42.87	8
Realized commodity hedging gain (loss)	**0.03**	(2.52)	(101)	**(0.09)**	(1.89)	(95)
Operating netback ($/Boe)[1]	**$ 46.85**	$ 51.72	(9)	**$ 46.32**	$ 40.98	13
Adjusted funds flow ($/Boe)[1]	**$ 36.85**	$ 40.44	(9)	**$ 35.93**	$ 30.80	17

(1) Refer to "Advisories and guidance" for information on Capital Management Measures and Ratios, Non-GAAP Financial Measures and Ratios and Supplemental Financial Measures.

Highlights for the three and nine months ended September 30, 2024

Production - Production in the third quarter of 2024 averaged 65,024 boe per day. The 5% quarter-over-quarter decline in production compared to the third quarter of 2023 was primarily due to the non-core Cardium asset disposition in November 2023, partially offset by successful drilling and development programs in both the Clearwater and Charlie Lake in the first nine months of 2024. The Company's oil and liquids weighting also grew to 85% compared to 82% primarily due to the higher relative natural gas-weighted dispositions and higher oil-weighted production from Clearwater wells brought on stream during the year.

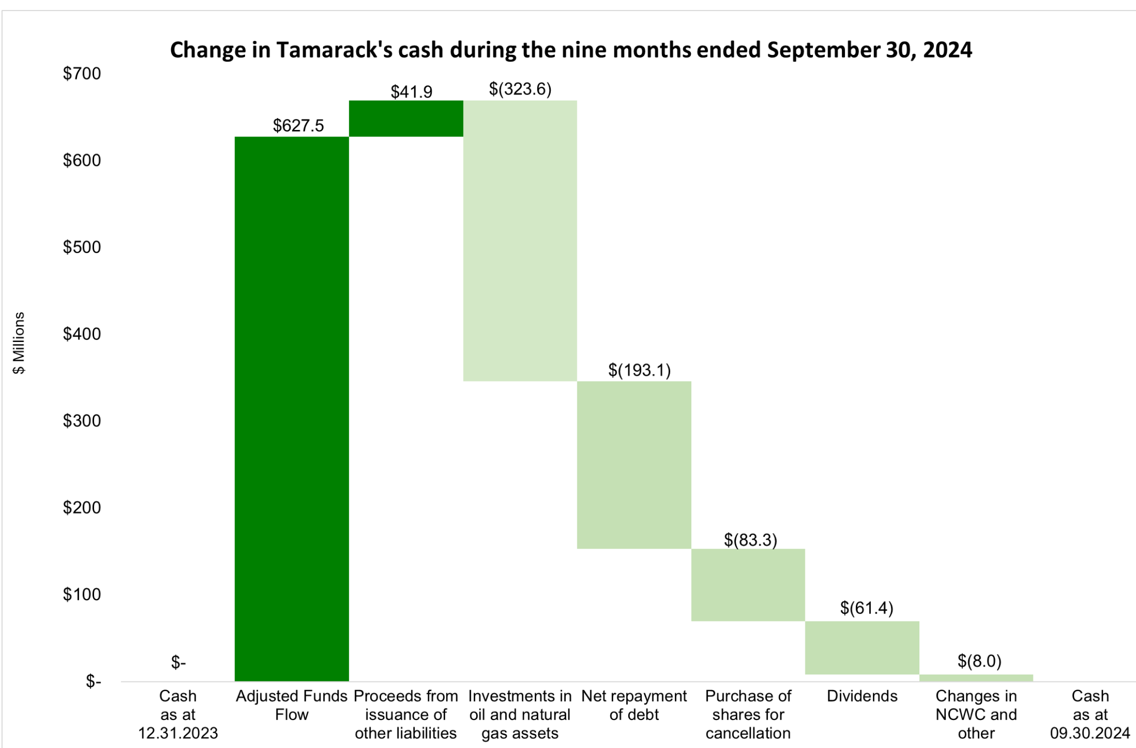
Realizations - Tamarack has continued to drive higher margins through improved heavy oil price realizations from ongoing marketing initiatives. In Q3 2024, the Company's heavy oil price differential, net of transportation expenses[1] relative to the Hardisty Heavy benchmark price, improved by 70% compared to Q3 2023. The Company's average gross realized price for its CWH blend (Clearwater Heavy Oil) sold at a premium to the WCS benchmark price for the first time during the third quarter of 2024. Tamarack's light oil price differential, net of transportation expenses[1] relative to the Edmonton Par benchmark price experienced a 38% improvement quarter-over-quarter

Cash Flows - Tamarack delivered cash provided by operating activities of $240.8 million during the three months ended September 30, 2024. The Company also delivered third quarter adjusted funds flow[1] of $220.4 million. Cash flows were supported by production outperformance, strong heavy oil price realizations and lower net production and transportation expenses.

Investments in Oil and Natural Gas Assets –Tamarack invested $109.0 million in Q3 2024 for ongoing development of the Clearwater and Charlie Lake plays. The Company's third quarter drilling program included 40.8 net Clearwater heavy oil wells and 4.0 net Charlie Lake light oil wells.

Clearwater Infrastructure Partnership Expansion - On September 17, 2024, Tamarack expanded the Clearwater Infrastructure Partnership to include a 13th Indigenous community to the arrangement. Under the terms of the agreement, Tamarack transferred additional Clearwater assets with a fair value of $50.8 million to the partnership for cash consideration of $43.2 million before transaction costs and a retained 15% operated working interest in exchange for increased fees over the existing 16-year term.

Shareholder Returns – Strong free funds flow[1] in the first nine months of 2024 of $297.7 million, together with proceeds from the Clearwater Infrastructure Partnership expansion, has allowed the Company to reduce its Net Debt[1] by $176.2 million year-to-date to $807.4 million. The Company has also repurchased and cancelled 22.0 million common shares at a total cost of $83.3 million and declared base dividends to shareholders of $61.4 million ($0.1125 per share). Since the beginning of 2022, Tamarack has now returned over $280.0 million to shareholders in the form of dividends and share buybacks. Tamarack plans to increase its annualized dividend of $0.15/share to $0.153/share starting in November 2024.



(1) Refer to "Advisories and guidance" for information on Capital Management Measures and Ratios, Non-GAAP Financial Measures and Ratios and Supplemental Financial Measures.

Annual guidance

2024 Outlook For the year ended December 31	Guidance (May 2024) 2024	Change 2024	Revised guidance (October 2024) 2024
Base 2024 capital investments budget ($ millions)(1)	390 - 440	-	**440**
Annual average production (boe/d)	61,000 - 63,000	2,000 - 1,000	**63,000 - 64,000**
Average oil & NGL weighting (%)	84 - 86	-	**84 - 86**
Royalty rate (%)	20 - 22	-	**20 - 22**
Corporate wellhead price differential - Oil	2.00 - 3.00	-	**2.00 - 3.00**
Net production ($/boe)(2)	8.75 - 9.25	-	**8.75 - 9.25**
Transportation ($/boe)	3.75 - 4.10	(0.30) - (0.35)	**3.45 - 3.75**
Carbon tax ($/boe)	0.50 - 1.00	(0.25) - (0.50)	**0.25 - 0.50**
General and administrative ($/boe)	1.35 - 1.50	-	**1.35 - 1.50**
Interest ($/boe)	3.80 - 4.20	(0.55) - (0.45)	**3.25 - 3.75**
Income taxes (% of Adjusted Funds flow before tax)	9 - 11	2	**11 - 13**

(1) Capital investments reflected in the table above reflects Tamarack's base 2024 budget and includes the impact of an incremental CSV Albright expansion budget of up to $20 million. Amounts also exclude decommissioning obligation expenditures, acquisitions, dispositions and Clearwater Infrastructure Partnership gas conservation projects.
(2) Refer to "Advisories and guidance" for information on Capital Management Measures and Ratios, Non-GAAP Financial Measures and Ratios and Supplemental Financial Measures.

Tamarack's capital investment program in 2024 continues to focus primarily on Clearwater and Charlie Lake drilling and development activities. 2024 investments include secondary recovery expansion of Clearwater waterflood projects at Nipisi and Marten Hills. Other capital projects consist of infrastructure expansions in the Clearwater area to support production growth.

In response to the continued strong well performance and benefits from infrastructure optimization during the year, the Company has increased the full-year production guidance range to 63,000 to 64,000 boe per day. The 2024 capital program, which is delivering higher production than originally budgeted, is forecasted to be achieved at a lower cost, benefitting from drilling and facilities efficiencies. Utilizing a portion of the proceeds from the Clearwater Infrastructure Partnership expansion, Tamarack will drill four Charlie Lake wells in the fourth quarter, expand regional pipeline capacity in advance of the third-party plant commissioning in early 2025, and expand its waterflood investment program in the Clearwater. Tamarack anticipates spending for the year to be approximately $440 million, consistent with prior guidance, which is inclusive of the incremental Charlie Lake wells and waterflood investment as the Company continues to out deliver against the capital deployed.

Transportation guidance was reduced in response to improved oil transportation contracts and lower trucking costs. Tamarack has reduced its carbon tax guidance reflecting the impact of lower anticipated taxable emissions in 2024 as a result of ongoing carbon abatement initiatives in the Clearwater area. Interest expense guidance was reduced primarily due to lower net debt and lower interest rates. Income tax guidance was increased to reflect profitability outperformance and the impact of the Clearwater Infrastructure Partnership. With all of the updates combined and the Clearwater Infrastructure Partnership expansion, the expected shareholder return profile and net debt levels are better in 2024 and beyond than what was contemplated in the original base budget announced in December 2023.

Production

	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Production						
Heavy oil (bbls/d)	**39,047**	35,900	9	**37,659**	35,229	7
Light oil (bbls/d)	**13,203**	16,974	(22)	**14,422**	16,797	(14)
Natural gas liquids (bbls/d)	**2,915**	3,623	(20)	**2,460**	3,795	(35)
Natural gas (mcf/d)	**59,154**	72,597	(19)	**55,162**	71,633	(23)
Total (boe/d)	**65,024**	68,597	(5)	**63,735**	67,760	(6)
Total (boe)	**5,982,212**	6,310,902	(5)	**17,463,251**	18,498,431	(6)
Percentage of oil and NGLs	**85%**	82%	4	**86%**	82%	5

Tamarack's production for the three and nine months ended September 30, 2024 decreased 5% and 6%, respectively, compared to the same periods in 2023, primarily due to non-core property dispositions in the fourth quarter of 2023 and first half of 2024 and base declines, partially offset by higher production from the Company's ongoing drilling and development programs in the Clearwater and Charlie Lake areas.

Tamarack's oil and NGL weighting for the three and nine months ended September 30, 2024 increased by 4% and 5%, respectively, compared to the same periods in 2023, primarily due to the higher relative natural gas-weighted property disposition in Q4 2023 and Clearwater oil wells brought on stream during the year.

Benchmark prices

September 30	Three months ended 2024	2023	% change	Nine months ended 2024	2023	% change
Benchmark pricing						
West Texas Intermediate (US$/bbl)	**$ 75.09**	$ 82.26	(9)	**$ 77.54**	$ 77.39	0
Western Canadian Select (WCS/Hardisty Heavy)(Cdn$/bbl)	**83.95**	93.09	(10)	**84.45**	80.38	5
WCS differential, relative to WTI (US$/bbl)	**13.55**	12.88	5	**15.49**	17.63	(12)
Edmonton Par (light sweet) (Cdn$/bbl)	**97.85**	107.90	(9)	**98.43**	100.63	(2)
Edmonton Par differential, relative to WTI (US$/bbl)	**3.35**	1.85	81	**5.21**	2.61	100
NYMEX monthly settlement (US$/mmbtu)	**2.16**	2.55	(15)	**2.10**	2.69	(22)
AECO daily index (Cdn$/mcf)	**0.69**	3.40	(80)	**1.45**	3.00	(52)
AECO monthly index (Cdn$/mcf)	**0.81**	2.37	(66)	**1.43**	3.01	(52)
Foreign exchange (USD to CAD)	**1.36**	1.34	1	**1.36**	1.35	1

The price of West Texas Intermediate ("WTI") for crude oil sales at Cushing, Oklahoma is the primary benchmark for crude oil pricing in North America. The differential price between Western Canadian crude and WTI is impacted by multiple factors including domestic production, inventory levels, pipeline capacity, US refinery intake capacity and storage constraints in Canada. The price that Tamarack receives for the sale of its crude oil is discounted for delivery points in Alberta and also adjusted for quality based on the actual density of the oil relative to the quoted benchmark.

During the three months ended September 30, 2024, the WTI benchmark decreased 9% compared to the same period in 2023, with global demand for oil softening combined with weaker economic data. During the nine months ended September 30, 2024, the WTI benchmark remained flat compared to the prior year as oil prices were supported by escalating regional conflicts in the middle east and Ukraine. In addition, ongoing production restrictions imposed by OPEC+ in the first half of the year, were mostly offset by growth in North American production and softening demand for oil in the third quarter.

The WCS differential weakened by 5% in Q3 2024 primarily due to unplanned US refinery downtime during the quarter. The differential strengthened by 12% for the first nine months of 2024 primarily due to the successful start-up of the TMX pipeline to the west coast. The Edmonton Par differential widened by 81% and 100% during the three and nine months ended September 30, 2024, primarily due to an over-supply of sweet oil in Alberta and higher inventory balances, particularly in the first quarter. Natural gas benchmarks declined in 2024 primarily due to the higher production in the WCSB, lower demand and persistently high natural gas storage levels following the mild winter.

Oil and natural gas sales

($ thousands, except per unit) September 30	Three months ended 2024	2023	% change	Nine months ended 2024	2023	% change
Revenue						
Heavy oil, net of blending expense(1)	**$ 306,256**	$ 306,663	(0)	**$ 858,412**	$ 732,392	17
Light oil	**118,777**	168,379	(29)	**382,152**	450,757	(15)
Natural gas	**4,753**	17,391	(73)	**26,006**	55,594	(53)
Natural gas liquids	**10,617**	13,820	(23)	**26,502**	43,004	(38)
Total, net of blending expense(1)	**$ 440,403**	$ 506,253	(13)	**$ 1,293,072**	$ 1,281,747	1
Average realized price:						
Heavy oil, net of blending expense ($/bbl)(1)	**$ 85.25**	$ 92.85	(8)	**$ 83.19**	$ 76.15	9
Light oil ($/bbl)	**97.79**	107.83	(9)	**96.71**	98.30	(2)
Natural gas ($/mcf)	**0.87**	2.60	(66)	**1.72**	2.84	(39)
Natural gas liquids ($/bbl)	**39.58**	41.46	(5)	**39.32**	41.51	(5)
Combined average oil and NGL ($/boe)	**85.84**	94.05	(9)	**84.79**	80.46	5
Revenue, net of blending expense ($/boe)(1)	**$ 73.62**	$ 80.22	(8)	**$ 74.05**	$ 69.29	7

(1) Refer to "Advisories and guidance" for information on Capital Management Measures and Ratios, Non-GAAP Financial Measures and Ratios and Supplemental Financial Measures.

For the three months ended September 30, 2024, revenues decreased by $65.9 million compared to the same period in 2023, due to lower realized prices of $41.7 million and lower production of $24.2 million. For the first nine months of 2024, revenues increased by $11.3 million compared to the same period in 2023, due to higher realized prices of $88.0 million, partially offset by lower production of $76.7 million.

The Company's realized price declined by 8% during the three months ending September 30, 2024, compared to the same quarter in 2023. The decrease was driven by lower oil benchmarks, weaker WCS and Edmonton Par differentials as well as significantly lower natural gas prices. The Company's realized price increased by 7% during the nine months ending September 30, 2024, compared to the same period in the prior year, primarily due to stronger WCS prices and differentials in the first half of the year.

Tamarack has continued to drive higher margins through improved heavy oil price realizations from ongoing marketing initiatives. The following table summarizes the Company's wellhead price realizations relative to quoted benchmark prices:

	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Heavy oil wellhead price realization ($/bbl)						
Hardisty Heavy benchmark price	**$ 83.95**	$ 93.09	(10)	**$ 84.45**	$ 80.38	5
Less: Tamarack's heavy oil realized price, net of blending	**(85.25)**	(92.85)	(8)	**(83.19)**	(76.15)	9
Heavy oil wellhead price differential[1]	**$ (1.30)**	$ 0.24	(642)	**$ 1.26**	$ 4.23	(70)
Add: Transportation expenses - heavy oil	**3.22**	6.24	(48)	**4.57**	6.36	(28)
Heavy oil differential, including transportation expenses[1]	**$ 1.92**	$ 6.48	(70)	**$ 5.83**	$ 10.59	(45)
Light oil wellhead price realization ($/bbl)						
Edmonton Par benchmark price	**$ 97.85**	$ 107.90	(9)	**$ 98.43**	$ 100.63	(2)
Less: Tamarack's light oil realized price	**(97.79)**	(107.83)	(9)	**(96.71)**	(98.30)	(2)
Light oil wellhead price differential[1]	**0.06**	0.07	(14)	**1.72**	2.33	(26)
Add: Transportation expenses - light oil	**2.12**	3.47	(39)	**3.40**	2.81	21
Light oil differential, including transportation expenses[1]	**$ 2.18**	$ 3.54	(38)	**$ 5.12**	$ 5.14	(0)

(1) Refer to "Advisories and guidance" for information on Capital Management Measures and Ratios, Non-GAAP Financial Measures and Ratios and Supplemental Financial Measures.

During the three and nine months ended September 30, 2024, the Company's heavy oil differential including transportation expenses improved by 70% and 45% compared to the same periods in 2023, respectively, reflecting the impact of higher flows into the Secure-Pembina Nipisi pipeline and blending terminal, optimized sales points for trucked heavy oil production, strong trading differentials driven by the TMX pipeline and the sales of CWH product (Clearwater Heavy Oil). Tamarack also recognized crown royalty transportation cost recoveries which improved the Heavy oil differential in the third quarter in 2024.

During the third quarter of 2024, the Company's light oil differential including transportation expenses improved by 38%, compared to the same period in the prior year, primarily due to lower transportation costs from crown royalty transportation recoveries.

Risk management

($ thousands, except per boe)	Three months ended		Nine months ended	
September 30	**2024**	2023	**2024**	2023
Realized gain (loss)	**$ 185**	$ (15,922)	**$ (1,642)**	$ (34,892)
Unrealized gain (loss)	**27,824**	(20,106)	**(6,385)**	(13,854)
Total risk management contracts	**$ 28,009**	$ (36,028)	**$ (8,027)**	$ (48,746)
Realized gain (loss) ($/boe)	**$ 0.03**	$ (2.52)	**$ (0.09)**	$ (1.89)

Changes in crude oil benchmarks and price differentials can have a significant impact on Tamarack's oil and natural gas sales, cash provided by operating activities and adjusted funds flow. Tamarack enters into risk management contracts on a prudent, non-speculative basis in order to reduce liquidity risk and stabilize near-term adjusted funds flow which allows the Company to fund capital investment programs, net debt reduction and the return of capital to shareholders.

Risk management instruments are measured at their estimated fair market value at each reporting period. An unrealized gain on commodity risk management contracts reflects a non-cash increase in value resulting from a decline in future estimated commodity prices relative to Tamarack's contract positions. A realized commodity risk management contract gain reflects the cash settlement of the Company's fixed price position relative to a lower actual underlying market price at the maturity date. Realized and unrealized losses generally result from increases in actual and future estimated commodity prices, respectively.

As at September 30, 2024, Tamarack's outstanding commodity risk management contracts had a net asset value of $29.5 million (December 31, 2023 – $35.9 million net asset).

Royalties

($ thousands, except per boe)	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Total royalty expenses	**$ 94,162**	$ 84,443	12	**$ 255,781**	$ 234,875	9
Total ($/boe)	**15.74**	13.38	18	**14.65**	12.70	15
Percentage of sales, net of blending (%)	**21**	17	24	**20**	18	11

Royalties as a percentage of sales, net of blending expense, for the three and nine months ended September 30, 2024 increased to 21% and 20%, respectively, compared to 17% and 18% in the same periods in the prior year, primarily due to a higher number of wells no longer subject to pre-payout royalty rates.

Net production expenses

($ thousands, except per boe)	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Production expenses	**$ 51,621**	$ 54,602	(5)	**$ 161,707**	$ 181,072	(11)
Less: processing income	**(49)**	(1,156)	(96)	**(2,367)**	(1,229)	93
Total net production expenses[1]	**$ 51,572**	$ 53,446	(4)	**$ 159,340**	$ 179,843	(11)
Total ($/boe)[1]	**$ 8.62**	$ 8.47	2	**$ 9.12**	$ 9.72	(6)

(1) Refer to "Advisories and guidance" for information on Capital Management Measures and Ratios, Non-GAAP Financial Measures and Ratios and Supplemental Financial Measures.

For the three months ended September 30, 2024, per unit net production expenses increased 2% compared to the same period in 2023, reflecting lower production and lower processing income. For the first nine months of 2024, per unit net production expenses declined by 6% compared to the same period in 2023, primarily due to field infrastructure investments, lower trucking costs from waterflood reinjection, lower energy costs, pipeline connections and the realization of synergies across the Clearwater asset areas at Nipisi and Marten Hills. Net production expenses also declined as a result of the non-core property dispositions in Q4 2023 and H1 2024 which carried higher relative operating costs on a per barrel basis relative to Tamarack's corporate averages.

Transportation expenses

($ thousands, except per boe)	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Transportation expense - oil	**$ 12,219**	$ 22,890	(47)	**$ 53,703**	$ 65,969	(19)
Transportation expense - gas	**1,907**	3,144	(39)	**6,933**	8,093	(14)
Total transportation expenses	**$ 14,126**	$ 26,034	(46)	**$ 60,636**	$ 74,062	(18)
Total ($/boe)	**$ 2.36**	$ 4.13	(43)	**$ 3.47**	$ 4.00	(13)

(1) Pipeline tariffs are generally classified as transportation expenses when the Company has firm commitments or contractual arrangements on the pipeline. Pipeline tariffs may also be included indirectly as a deduction from the base price paid by a purchaser of Tamarack's oil, NGL and gas sales. In the latter case, the tariffs are reflected as a reduction of revenue.

For the three and nine months ended September 30, 2024, transportation expenses per boe decreased by 43% and 13%, respectively, compared to the same periods in 2023, primarily due to lower transportation expenses in respect of the Company's Secure-Pembina Nipisi pipeline oil transportation contract, pipeline infrastructure investments and reduced trucking activities. The Company also recognized certain crown royalty transportation cost recoveries during the third quarter. The Company's overall transportation expenses decreased by 46% and 18%, for the three and nine months ended September 30, 2024, respectively, primarily due to lower production from the sale of the Cardium assets in November 2023 and the lower oil transportation tariffs.

Operating netback

($/boe)	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Realized sales price, net of blend expense[1]	**$ 73.62**	$ 80.22	(8)	**$ 74.05**	$ 69.29	7
Royalty expenses	**(15.74)**	(13.38)	18	**(14.65)**	(12.70)	15
Net production expenses[1]	**(8.62)**	(8.47)	2	**(9.12)**	(9.72)	(6)
Transportation expenses	**(2.36)**	(4.13)	(43)	**(3.47)**	(4.00)	(13)
Carbon tax	**(0.08)**	-	nm	**(0.40)**	-	nm
Operating field netback[1]	**$ 46.82**	$ 54.24	(14)	**$ 46.41**	$ 42.87	8
Realized hedging gain (loss)	**0.03**	(2.52)	(101)	**(0.09)**	(1.89)	(95)
Operating netback[1]	**$ 46.85**	$ 51.72	(9)	**$ 46.32**	$ 40.98	13

(1) Refer to "Advisories and guidance" for information on Capital Management Measures and Ratios, Non-GAAP Financial Measures and Ratios and Supplemental Financial Measures.

($ thousands)	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Realized sales price, net of blend expense[1]	**$ 440,403**	$ 506,253	(13)	**$ 1,293,072**	$ 1,281,747	1
Royalty expenses	**(94,162)**	(84,443)	12	**(255,781)**	(234,875)	9
Net production expenses[1]	**(51,572)**	(53,446)	(4)	**(159,340)**	(179,843)	(11)
Transportation expenses	**(14,126)**	(26,034)	(46)	**(60,636)**	(74,062)	(18)
Carbon tax	**(483)**	-	nm	**(6,942)**	-	nm
Operating field netback[1]	**$ 280,060**	$ 342,330	(18)	**$ 810,373**	$ 792,967	2
Realized hedging gain (loss)	**185**	(15,922)	(101)	**(1,642)**	(34,892)	(95)
Operating netback[1]	**$ 280,245**	$ 326,408	(14)	**$ 808,731**	$ 758,075	7

(1) Refer to "Advisories and guidance" for information on Capital Management Measures and Ratios, Non-GAAP Financial Measures and Ratios and Supplemental Financial Measures.

For the three months ended September 30, 2024, the operating netback per boe decreased 9% compared to the same period in 2023 primarily due to lower commodity prices and higher royalty rates, partially offset by lower transportation expenses and a realized hedging gain. For the nine months ended September 30, 2024, the operating netback per boe increased by 13% compared to the prior year, primarily due to higher heavy oil commodity prices (in the first half of the year), lower net production and transportation expenses and lower realized hedging losses partially offset by higher royalty rates. Carbon tax in 2024 has been lower than expected with ongoing abatement initiatives in the Clearwater area and lower market prices for carbon credits.

General and administrative ("G&A") expenses

($ thousands, except per boe)	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
G&A costs	**$ 11,093**	$ 10,781	3	**$ 34,805**	$ 31,951	9
Less: capitalized costs and recoveries	**(3,485)**	(2,842)	23	**(10,201)**	(8,453)	21
G&A expenses	**$ 7,608**	$ 7,939	(4)	**$ 24,604**	$ 23,498	5
Total ($/boe)	**$ 1.27**	$ 1.26	1	**$ 1.41**	$ 1.27	11

For the nine months ended September 30, 2024, G&A costs per boe increased by 11% compared to the same period in 2023, primarily due to increased staffing costs, higher legal and other expenses incurred in the first quarter of 2024 and lower production.

Stock-based compensation expense

($ thousands, except per boe)	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Stock-based compensation costs	**$ 5,570**	$ 4,392	27	**$ 16,208**	$ 16,030	1
Less: capitalized costs	**(1,818)**	(1,442)	26	**(4,433)**	(3,497)	27
Stock-based compensation expense	**$ 3,752**	$ 2,950	27	**$ 11,775**	$ 12,533	(6)
Total ($/boe)	**$ 0.63**	$ 0.47	34	**$ 0.67**	$ 0.68	(1)

Stock-based compensation expense for Q3 2024 increased 27% compared to Q3 2023 primarily due to an increase in Tamarack's share price in the third quarter of 2024. Stock-based compensation expense for the nine months ended September 30, 2024, decreased by 6% compared to the same period in 2023, primarily due to the payouts of cash-settled units in 2023 and changes in share price, partially offset by new grants issued in 2024.

Finance expense

($ thousands, except per boe)	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Syndicated Facility	**$ 9,932**	$ 17,367	(43)	**$ 34,413**	$ 45,924	(25)
Senior Notes	**5,482**	5,482	-	**16,298**	16,298	-
Clearwater infrastructure liability	**3,704**	-	nm	**10,866**	-	nm
DAP Notes	**-**	2,271	(100)	**792**	8,913	(91)
Other interest and fees	**96**	(105)	(191)	**551**	1,817	(70)
Cash interest expense	**$ 19,214**	$ 25,015	(23)	**$ 62,920**	$ 72,952	(14)
Deferred borrowing costs and loan accretion	**1,858**	1,982	(6)	**5,889**	5,738	3
Unrealized foreign exchange loss on debt	**210**	6,724	(97)	**2,637**	1,432	84
Unrealized gain on cross-currency swaps	**(146)**	(6,634)	(98)	**(2,729)**	(1,411)	93
Accretion of decommissioning obligations	**1,392**	1,864	(25)	**4,464**	6,103	(27)
Finance expense	**$ 22,528**	$ 28,951	(22)	**$ 73,181**	$ 84,814	(14)
Total cash interest expense ($/boe)	**$ 3.21**	$ 3.96	(19)	**$ 3.60**	$ 3.94	(9)

For the three and nine months ended September 30, 2024, cash interest expense decreased by 23% and 14%, respectively, compared to the same periods in the prior year, primarily due to the lower average balances of the Syndicated Facility and repayment of the DAP Notes, partially offset by interest expense recognized on the Clearwater infrastructure liability that was issued in the fourth quarter of 2023. The Company also incurred lower interest rates on bank debt, particularly in the third quarter of 2024 following rate cuts by the central bank that commenced in June 2024.

The Company amortizes capitalized issuance costs over the term of its corresponding debt instrument and incurs standby fees on the undrawn portion of the Syndicated Facility. Financing expenses include the realized and unrealized gains and losses resulting from the revaluation of outstanding US dollar denominated credit facility draws at each reporting period, as well as the corresponding foreign exchange cross-currency swap contracts that are aligned with these hedged credit facility draws. Offsetting realized gains and losses from the net settlement of these financial instruments are reflected net in the table above.

Income taxes

($ thousands)	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Current income tax expense	**$ 31,031**	$ 35,482	(13)	**$ 85,699**	$ 80,241	7
Deferred income tax expense (recovery)	**370**	(31,816)	(101)	**(43,218)**	(64,201)	(33)
Total income tax expense	**$ 31,401**	$ 3,666	757	**$ 42,481**	$ 16,040	165
Statutory tax rate	**23%**	23%	-	**23%**	23%	-
Effective tax rate	**25%**	30%	(17)	**21%**	30%	(30)

Total income tax expense for the three and nine months ended September 30, 2024 increased by 757% and 165%, respectively, compared to the same periods in the prior year, primarily due to impairment losses on disposed assets recognized in 2023, higher operating earnings in 2024 and the Clearwater Infrastructure Partnership transaction.

Depletion, depreciation and amortization (“DD&A”)

($ thousands, except per boe)	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Depletion, depreciation and amortization	**$ 149,422**	$ 161,322	(7)	**$ 446,253**	$ 480,317	(7)
Total ($/boe)	**$ 24.98**	$ 25.56	(2)	**$ 25.55**	$ 25.97	(2)

For the three and nine months ended September 30, 2024, DD&A expense per boe was relatively consistent with the prior year. Gross DD&A expense during the first nine months of 2024 decreased by 7% primarily due to lower production volumes.

Adjusted funds flow and net income

($ thousands, except per share amounts)	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Cash provided by operating activities	**$ 240,843**	$ 199,756	21	**$ 631,414**	$ 415,645	52
Decommissioning expenditures	**2,699**	3,583	(25)	**6,242**	4,768	31
Changes in non-cash working capital	**(23,123)**	51,860	(145)	**(10,127)**	149,310	(107)
Adjusted funds flow(1)	**220,419**	255,199	(14)	**627,529**	569,723	10
Per share - basic(1)	**0.41**	0.46	(11)	**1.15**	1.02	13
Per share - diluted(1)	**0.40**	0.46	(13)	**1.14**	1.02	12
Net income	**$ 93,694**	$ 8,634	985	**$ 155,837**	$ 36,874	323
Per share - basic	**0.17**	0.02	750	**0.28**	0.07	300
Per share - diluted	**0.17**	0.02	750	**0.28**	0.07	300

(1) Refer to "Advisories and guidance" for information on Capital Management Measures and Ratios, Non-GAAP Financial Measures and Ratios and Supplemental Financial Measures.

Cash provided by operating activities increased by 21% and 52%, respectively, for the three and nine months ended September 30, 2024, compared to the same periods in the prior year, primarily due to a full year of 2022 tax instalments remitted to the Government in the first nine months of 2023 (reflected through non-cash working capital). Adjusted funds flow for the three months ended September 30, 2024 decreased by 14% compared to the prior year primarily due to lower production and lower sales prices. Adjusted funds flow increased by 10% for the nine months ended September 30, 2024 primarily due to higher operating netbacks (in the first half of the year) and lower financing expenses in 2024, partially offset by lower production.

The Company recorded net income of $93.7 million during the three months ended September 30, 2024, compared to net income of $8.6 million in the same period in 2023, primarily due to a loss on the Cardium assets held for sale during the third quarter of 2023, partially offset by lower adjusted funds flow. For the nine months ended September 30, 2024, Tamarack recorded net income of $155.8 million, compared to $36.9 million in the same period in 2023, primarily due to higher adjusted funds flow during the first nine months of 2024 and losses on dispositions and risk management contracts in the first nine months of 2023.

Investments in oil and natural gas assets

($ thousands)	Three months ended			Nine months ended		
September 30	**2024**	2023	% change	**2024**	2023	% change
Drilling, completion and equipping	**$ 96,839**	$ 85,660	13	**$ 239,957**	$ 262,117	(8)
Facilities	**11,048**	36,157	(69)	**69,606**	116,665	(40)
Land, seismic and other	**1,145**	942	22	**14,031**	9,970	41
Investments in oil and natural gas assets	**$ 109,032**	$ 122,759	(11)	**$ 323,594**	$ 388,752	(17)
Acquisitions	**-**	800	(100)	**-**	15,887	(100)
Dispositions	**(1,076)**	(38,987)	(97)	**641**	(41,438)	(102)

The following table summarizes the number of wells drilled during the three and nine months ended September 30, 2024 and 2023:

Net wells drilled	Three months ended		Nine months ended	
September 30	**2024**	2023	**2024**	2023
Clearwater	**38.4**	40.3	**86.1**	91.6
Charlie Lake	**4.0**	1.0	**9.4**	13.8
	42.4	41.3	**95.5**	105.4

2024 capital investments included numerous infrastructure expansion projects in the Clearwater area for gas conservation, field interconnect pipelines, oil treating and water injection. These infrastructure investments have continued to facilitate production growth, net production expense reductions and the abatement of greenhouse gas emissions.

Clearwater Infrastructure Partnership

The Clearwater Infrastructure Partnership liability reflects an Indigenous-held 85% share of Tamarack's 16-year take-or-pay commitment to the partnership for the utilization of certain infrastructure assets in the Clearwater area. Tamarack holds a 15% operated share of the partnership and is responsible for all associated operating and maintenance costs. The Company has retained full access to 100% of the partnership's midstream capacity and priority access to any incremental capacity above the minimum take-or-pay commitment, where volumes can be utilized on a prescribed fee-for-service basis.

On September 17, 2024, Tamarack expanded the Clearwater Infrastructure Partnership to include a 13th Indigenous community to the arrangement. Tamarack transferred additional Clearwater midstream assets with a fair value of $50.8 million to the partnership for cash consideration of $43.2 million before transaction costs and retained 15% operated working interest. In exchange, Tamarack assumed higher fees on the pre-existing 16-year take-or-pay commitment with average throughput volumes of 29,000 boe per day.

Dispositions

During the nine months ended September 30, 2024 the Company sold certain non-core oil and natural gas assets to third-parties for nominal consideration and recorded a loss on disposal of $46.5 million. As part of the dispositions, Tamarack reduced undiscounted and uninflated decommissioning obligations by $20.3 million.

Liquidity and capital resources

The Company actively manages capital and liquidity risk through the continuous monitoring of asset performance, forecasting anticipated future cash flows in conjunction with the design of the annual capital investment programs, maintaining available credit under bank facilities, managing debt maturity dates, hedging a portion of the Company's production, judiciously assessing new capital investment, acquisition or divestment opportunities and the pursuit of new liquidity, if necessary. The Company believes that available credit and future anticipated adjusted funds flow will be sufficient to fund Tamarack's 2024 and 2025 capital development programs, dividends and any share repurchases.

The Company continues to prioritize shareholder returns and net debt reduction with free funds flow generated from the business. The following table summarizes free funds flow for the three and nine months ended September 30, 2024:

	Three months ended		Nine months ended	
September 30	**2024**	2023	**2024**	2023
Adjusted funds flow	**$ 220,419**	$ 255,199	**$ 627,529**	$ 569,723
Decommissioning obligation expenditures	**(2,699)**	(3,583)	**(6,242)**	(4,768)
Investments in oil and natural gas assets	**(109,032)**	(122,759)	**(323,594)**	(388,752)
Free funds flow	**$ 108,688**	$ 128,857	**$ 297,693**	$ 176,203

Shareholder returns

Tamarack continues to distribute a monthly base dividend of $0.0125 per common share which commenced in 2022. In January 2024, Tamarack initiated an enhanced shareholder return program by applying for a normal course issuer bid and receiving approval from the TSX to purchase up to 54.6 million Tamarack common shares until January 18, 2025. During the nine months ended September 30, 2024, the Company purchased and cancelled 22.0 million common shares at an average price of $3.71 per common share, for a total repurchase cost of $83.3 million, including $1.6 million of taxes. Tamarack achieved its second debt threshold within its return of capital framework during the second quarter of 2024 allowing for an expansion of the Company's share buyback program. The following table summarizes the shareholder returns from 2022 to the third quarter of 2024:

Year to Date	Cumulative dividend per common share	Total dividends distributed	Shares retired through NCIB (thousands)	Total NCIB repurchases	Total shareholder returns
December 31, 2022	$ 0.1165	**$ 55,268**	-	**$ -**	$ 55,268
December 31, 2023	$ 0.1500	**83,521**	-	**-**	83,521
September 30, 2024	$ 0.1125	**61,378**	22,026	**83,323**	144,701
Total		**$ 200,167**	22,026	**$ 83,323**	$ 283,490

Tamarack plans to increase its annualized dividend of $0.15/share to $0.153/share starting in November 2024.

Net debt

Tamarack utilizes adjusted funds flow and net debt as capital management measures to assess financial performance and liquidity. As at September 30, 2024, the Company's ratio of net debt to annualized third quarter adjusted funds flow improved to 0.9 (December 31, 2023 – 1.3). The following table summarizes the composition of the Company's net debt for the periods indicated:

($ thousands)	**September 30, 2024**	December 31, 2023	September 30, 2023
Accounts payable and accrued liabilities	**$ 193,633**	$ 201,531	$ 211,157
Cross currency swap liability (asset)	**2,443**	5,172	(657)
Accounts receivable	**(132,489)**	(141,041)	(209,320)
Prepaid expenses and deposits	**(6,724)**	(18,024)	(23,155)
Working capital deficiency (surplus)(1)	**56,863**	47,638	(21,975)
Note receivable	**-**	-	(20,000)
Debt	**724,080**	909,758	1,244,957
Assets held for sale, net	**-**	-	(100,208)
Government loan and other	**26,458**	26,189	25,256
Net debt(1)	**$ 807,401**	$ 983,585	$ 1,128,030
Current quarter adjusted funds flow(1)	**$ 220,419**	$ 194,771	$ 255,199
Annualized factor	**4**	4	4
Annualized adjusted funds flow(1)	**$ 881,676**	$ 779,084	$ 1,020,796
Net debt to annualized adjusted funds flow(1)	**0.9 x**	1.3 x	1.1 x

(1) Refer to "Advisories and guidance" for information on Capital Management Measures and Ratios, Non-GAAP Financial Measures and Ratios and Supplemental Financial Measures.

Net debt declined by $176.2 million in the first nine months of 2024, and $320.6 million since the third quarter of 2023, primarily due to the allocation of free cash flow in excess of shareholder returns, proceeds from the Cardium disposition and the two Clearwater Infrastructure Partnership transactions which occurred in the fourth quarter of 2023 and third quarter of 2024.

Debt instruments

	Credit Facility	Senior Notes	Term Facility	DAP Notes	Total
Balance at December 31, 2023	$ 479,168	$ 290,423	$ 83,500	$ 56,667	**$ 909,758**
Repayment of debt instruments, net	(52,943)	-	(83,500)	(56,667)	**(193,110)**
Unrealized foreign exchange loss	2,637	-	-	-	**2,637**
Amortization of deferred borrowing costs	2,661	2,134	-	-	**4,795**
Balance at September 30, 2024	**$ 431,523**	**$ 292,557**	**$ -**	**$ -**	**$ 724,080**
Presented as:					
Current liabilities	$ -	$ -	$ -	$ -	**$ -**
Non-current liabilities	$ 431,523	$ 292,557	$ -	$ -	**$ 724,080**
Effective interest rate (annualized)	7.66%	8.19%	9.06%	5.75%	
Maturity date	April 30, 2027	May 10, 2027	-	-	

As at September 30, 2024, Tamarack has access to a $875.0 million three-year covenant-based revolving lending facility (the "Credit Facility"). During the second quarter of 2024, the Credit Facility was amended primarily to extend the maturity date by one year to April 30, 2027. The amended facility also included an uncommitted accordion feature that provides Tamarack with the ability to access an incremental $125.0 million of secured debt, subject to certain conditions, including approvals from the lending syndicate. As at September 30, 2024 Tamarack had undrawn capacity of $416.2 million.

The Credit Facility, together with a two-year secured amortizing term-loan (the "Term Facility") collectively formed Tamarack's syndicated, covenant-based credit facility (the "Syndicated Facility"). The Term Facility was a covenant-based, non-revolving lending arrangement with a maturity date of October 13, 2024 that was fully repaid in the first quarter of 2024.

The Company carries $300.0 million of 7.25% interest-bearing senior unsecured notes maturing on May 10, 2027 (the "Senior Notes"). The Senior Notes pay interest semi-annually in arrears with the principal amount repayable at the date of maturity. The Company also issued $300.0 million aggregate principal amount of 5.75% interest-bearing deferred acquisition payments (the "DAP Notes") in connection with the Deltastream Acquisition in 2022. The DAP Notes were fully repaid in the first quarter of 2024.

Financial covenants on debt

Covenant	September 30, 2024	Covenant
Total Debt to EBITDA ratio	**0.8:1.0**	<3.5:1.0
Senior Debt to EBITDA ratio	**0.5:1.0**	<3.0:1.0
Interest Coverage ratio	**12.1:1.0**	>3.0:1.0

Commitments and contingencies

	2024	2025	2026	2027	2028+	Total
Credit Facility	$ -	$ -	$ -	$ 452,871	$ -	**$ 452,871**
Senior Notes	-	-	-	300,000	-	**300,000**
Accounts payable and accrued liabilities	187,070	6,563	-	-	-	**193,633**
Risk management contracts	2,443	-	-	-	-	**2,443**
Clearwater Infrastructure Partnership (CIP)	1,696	7,023	7,802	8,667	155,178	**180,366**
Other liabilities, excluding CIP	2,521	13,012	11,100	13,649	6,682	**46,964**
Financial liabilities on the balance sheet	193,730	26,598	18,902	775,187	161,860	**1,176,277**
Interest on debt and other liabilities	18,010	71,339	70,168	34,985	113,727	**308,229**
Take-or-pay commitments	8,422	34,845	31,677	30,841	86,622	**192,407**
Processing commitments	1,609	10,247	14,242	14,242	128,256	**168,596**
Other capital commitments	3,000	-	-	-	-	**3,000**
Total financial commitments	$ 224,771	$ 143,029	$ 134,989	$ 855,255	$ 490,465	**$1,848,509**

Tamarack is involved in legal claims against the Company that have arisen in the normal course of business. While the final outcomes of such claims cannot be predicted with certainty and could be material, Tamarack believes that the claims are without merit and the amounts are unsubstantiated. The Company also does not anticipate that any of these legal proceedings will have a material impact on Tamarack's consolidated financial position or results of operations. Accordingly, no provision has been recorded in the Interim Financial Statements.

Share capital

The following table summarizes the Company's outstanding common shares and stock-based compensation units issued and outstanding as at the dates listed:

(thousands)	October 29, 2024	September 30, 2024	December 31, 2023
Common shares outstanding	**530,984**	534,283	556,183
Common shares held in treasury	**566**	638	758
Total common shares	**531,550**	534,921	556,941
Equity-settled stock options	**360**	360	1,037
Equity-settled RSUs	**4,891**	4,953	3,587
Equity-settled PSUs	**2,867**	2,877	2,143
Cash-settled RIAs	**943**	943	810
Cash-settled PIAs	**4,344**	4,344	3,850

Pursuant to Tamarack's stock-based compensation plans, the Company may grant up to an aggregate of 37.5 million equity compensation units to officers, employees, directors and consultants of the Company or its subsidiaries ("service providers"). During the nine months ended September 30, 2024, the Company issued 7.0 million stock-based awards at a weighted average fair value of $3.70 per share which was primarily based on the Company's share price at the date of grant. Tamarack utilized acquired treasury shares to settle 3.9 million stock-based compensation units that were exercised in the first nine months of 2024 resulting in no dilution of Tamarack's outstanding common shares.

Selected quarterly information

	Sept. 30, 2024	Jun. 30, 2024	Mar. 31, 2024	Dec. 31, 2023	Sept. 30, 2023	Jun. 30, 2023	Mar. 31, 2023	Dec. 31, 2022
Sales volumes								
Natural gas *(mcf/d)*	**59,154**	54,856	51,431	58,419	72,597	68,027	74,293	68,355
Oil and NGL *(bbls/d)*	**55,165**	55,000	53,450	55,144	56,497	55,400	55,556	52,951
Average boe/d *(6:1)*	**65,024**	64,143	62,022	64,881	68,597	66,738	67,938	64,344
Product prices								
Natural gas *($/mcf)*	**0.87**	1.51	2.93	2.82	2.60	2.39	3.50	4.89
Oil and NGL *($/bbl)*	**85.65**	90.70	78.04	79.58	94.07	76.24	71.03	80.38
Oil equivalent *($/boe)*	**73.46**	79.06	69.69	70.17	80.24	65.72	61.91	71.34
Financial results (000s, except per share amounts)								
Gross revenues	**439,435**	461,479	393,336	418,864	506,365	399,155	378,546	422,313
Cash provided by operating activities	**240,843**	225,370	165,201	215,981	199,756	156,265	59,624	227,889
Adjusted funds flow(2)	**220,419**	225,554	181,556	194,771	255,199	157,253	157,271	196,746
Per share – basic(2)	**0.41**	0.41	0.33	0.35	0.46	0.28	0.28	0.36
Per share – diluted(2)	**0.40**	0.41	0.33	0.35	0.46	0.28	0.28	0.36
Net income (loss)	**93,694**	94,887	(32,744)	57,322	8,634	25,735	2,505	50,441
Per share – basic	**0.17**	0.17	(0.06)	0.10	0.02	0.05	0.00	0.09
Per share – diluted	**0.17**	0.17	(0.06)	0.10	0.02	0.05	0.00	0.09
Operating netback(2)	**280,245**	291,386	237,101	251,172	326,408	222,712	208,955	250,087
Investment in oil and natural gas assets	**109,032**	86,341	128,221	127,704	122,759	117,831	148,162	125,276
Acquisitions(1)	**–**	–	–	1,612	800	12,148	2,939	1,447,973
Dispositions(1)	**(1,076)**	(80)	1,797	(100,038)	(38,987)	(2,271)	(180)	(21,873)
Total assets	**3,998,420**	4,028,689	4,116,037	4,208,128	4,443,837	4,559,903	4,593,760	4,619,701
Net debt(2)	**807,401**	882,669	984,768	983,585	1,128,030	1,373,620	1,374,068	1,356,570
Debt	**724,080**	866,647	924,517	909,758	1,244,957	1,329,581	1,286,718	1,195,206
Dividends declared per share	**0.0375**	0.0375	0.0375	0.0375	0.0375	0.0375	0.0375	0.0350
Decommissioning obligations	**168,966**	161,817	166,135	189,971	166,868	266,898	265,374	264,988

(1) Includes cash and non-cash consideration.

(2) Refer to "Advisories and guidance" for information on Capital Management Measures and Ratios, Non-GAAP Financial Measures and Ratios and Supplemental Financial Measures.

Significant factors and trends that have impacted the Company's results during the above quarterly periods include:

- Volatility in commodity prices and differentials and the resulting effect on revenue, cash provided by operating activities, adjusted funds flow and earnings.
- The volatility in decommissioning obligations due to fluctuations in discount rates, acquisitions and dispositions.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices, foreign exchange and interest rates which can cause significant fluctuations in earnings due to unrealized gains and losses recognized on a quarterly basis.
- On October 13, 2022, Tamarack closed the acquisition of Deltastream. The assets include approximately 19,500 boe per day of oil weighted assets, along with adding 184 net sections in the Clearwater oil play of Alberta for a total purchase consideration of approximately $1.4 billion.
- On July 31, 2023, the Company issued a GORR on select portions of its Clearwater and Charlie Lake oil properties and sold a working interest in the Company's Wembley gas plant to a third party for cash proceeds of $39.5 million.
- On November 3, 2023, the Company sold its non-core Cardium assets for gross cash consideration of $123.0 million and recorded a loss on the disposal of $111.7 million. Net proceeds were $98.9 million. The disposed assets included production of approximately 7,000 boe per day.
- On December 15, 2023, Tamarack and 12 First Nations and Métis communities formed the Clearwater Infrastructure Partnership whereby participating communities acquired an 85% non-operated working interest in Tamarack infrastructure assets in the Clearwater area with a fair value of $172.0 million for total consideration of $146.2 million and a 15% operated working interest in the partnership.
- On March 1, 2024, the Company sold certain non-core Redwater oil and natural gas assets for nominal consideration and recorded a loss of $38.0 million. The disposition included a reduction of decommissioning obligations of $14.2 million. The disposed assets included production of approximately 400 boe per day.
- On September 17, 2024, Tamarack expanded the Clearwater Infrastructure Partnership to include a 13th Indigenous community partner to the arrangement. The Company transferred Clearwater assets with a fair value of $50.8 million into the partnership for cash consideration of $43.2 million and a retained 15% interest in the partnership.

Advisories and guidance

Critical accounting policies, estimates and judgments

Tamarack utilized significant estimates, assumptions and judgments in order to apply the relevant accounting policies to the preparation of the Interim Financial Statements in accordance with International Accounting Standards 34 *Interim Financial Reporting*. A summary of this information can be found in Notes 2-4 of the annual financial statements. The key accounting policies of the Company that are subject to significant estimates, assumptions or judgments consist of oil and natural gas assets, impairment, financial instruments, provisions, income taxes and the basis of consolidation. There were no new or significant updates to the application of the Company's critical accounting policies, estimates, assumptions or judgments during the three and nine months ended September 30, 2024.

Certain comparative figures in the Interim Financial Statements have been adjusted to conform with the current period presentation. On the statement of income and comprehensive income, product purchases and sales of purchased product were disaggregated from oil and natural gas sales. On the statement of cash flows, accrued current income tax expense, non-cash finance expense, net proceeds from other liabilities, and dividends have been reflected separately from changes in non-cash working capital. There were no changes to the consolidated operating results or financial position for the nine months ended September 30, 2023 as a result of these presentation changes.

Non–GAAP financial measures and non-GAAP financial ratios

This document contains the terms "revenue, net of blending expense", "net production expenses", "operating netback", "operating field netback", "heavy oil differential including transportation expenses", "light oil differential including transportation expenses" and "free funds flow", which are non-GAAP financial measures, or ratios if calculated on a per boe or per share basis. These non-GAAP financial measures and ratios do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable to similar measures presented by other issuers without taking into account the method by which the measures are prepared. These performance measures should not be considered in isolation or as a substitute for performance measures prepared in accordance with IFRS and should be read in conjunction with the annual financial statements. Refer to the discussion of the Company's operating results and the "Liquidity and Capital Resources" section of this MD&A for further details regarding the calculation and measurement of these measures.

The non-GAAP financial ratios consisting of non-GAAP measures presented on a per share basis are determined by dividing the value of the financial measure by the weighted average common shares outstanding and diluted weighted average common shares outstanding during the period. These per share disclosures allow Tamarack and others to understand the value of selected financial information that is attributable to each common shareholder. The non-GAAP financial ratios consisting of non-GAAP measures presented on a per boe basis are determined by dividing the value of the financial measure by the sales volumes in the period. These per boe disclosures allow Tamarack and others to assess the profitability of each barrel of oil equivalent produced, and also facilitates a comparison of current period performance to historical periods, or to peer results, by isolating the impact of differences in production volumes.

Revenue, net of blending expense

Blending expense (recovery) consists of the cost of blending diluent that is purchased to reduce the viscosity of heavy oil transported through pipelines to meet minimum flow rate specifications. The blending expense (recovery) represents the differential between the cost of purchasing and transporting the diluent and the realized price of the blended product sold. In this MD&A, blending expense (recovery) is recognized as a reduction to heavy oil revenues, whereas blending expense (recovery) is reported as an expense in the Interim Financial Statements. Revenue, net of blending expenses allows Tamarack and others to assess the performance of the Company's net realized price from marketing downstream sales by including the associated cost of diluent that was purchased and resold within the blended stream. Revenue, net of blending expenses is also presented on a per boe basis as a non-GAAP financial ratio.

Heavy and light oil differentials including transportation expenses

The calculation of the Company's heavy oil differential including transportation expenses and light oil differential including transportation expenses, is presented in the "Petroleum and natural gas sales" section of this MD&A and is determined by comparing the Company's realized price on a per barrel basis to the published benchmark price, including the impact of transportation expenses. The Company and others utilize this performance measure to assess the value of net wellhead 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-GAAP financial ratio.

Net production expenses

Tamarack generates processing income from third parties that utilize excess capacity at Tamarack's facilities. In this MD&A, processing income is recognized as a reduction to production expenses, whereas processing income is reported as other income in the Interim Financial Statements. If Tamarack has excess capacity at one of its facilities, the Company will seek to process third-party volumes as a means to reduce the cost of operating those facilities. Accordingly, net production expenses allow Tamarack and others to assess the performance of its field and facility operating results by including the associated income generated from plant operations. Net production expenses are also presented on a per boe basis as a non-GAAP financial ratio.

Operating netback and operating field netback

The calculation of the Company's Operating Netback and Operating Field Netback is presented in the operating results section of this MD&A. Tamarack and others utilize the Operating Netback and Operating Field Netback measures to assess the operational performance of the Company's assets areas by isolating the impact of corporate and other overhead related expenditures. These metrics are also presented on a per boe basis as a non-GAAP financial ratio.

Free funds flow

Free funds flow is defined as adjusted funds flow less investments in oil and natural gas assets and decommissioning expenditures. Management utilizes free funds flow to assess how much cash was generated in excess of the Company's capital investment and decommissioning programs within the same period, which can be utilized to reduce net debt, fund acquisitions or return capital to shareholders. Free funds flow is also presented on a per share basis as a non-GAAP financial ratio.

Capital Management Measures and Ratios

This document contains capital management measures of "adjusted funds flow", "net debt", "working capital deficiency (surplus)" and "net debt to annualized adjusted funds flow" which the Company utilizes to manage its capital. Refer to Note 13 of the Interim Financial Statements for further details. These capital management measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers without taking into account the method by which the measures are prepared. These performance measures should not be considered in isolation or as a substitute for performance measures prepared in accordance with IFRS and should be read in conjunction with the annual financial statements. Refer to the discussion of the Company's operating results and the "Liquidity and Capital Resources" section for further details regarding the calculation of these measures.

Adjusted funds flow

Adjusted funds flow is defined as cash provided by operating activities excluding decommissioning obligation expenditures, transaction costs and changes in non-cash working capital. Decommissioning 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. Decommissioning obligation expenditures also 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 generally 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 and adjusted funds flow per boe are supplemental financial measures and are calculated by dividing adjusted funds flow by the Company's weighted average basic and diluted shares outstanding, and total sales volumes during the period, respectively.

Net debt and working capital deficiency (surplus)

The calculation of the Company's Net Debt and Working Capital Deficiency (surplus) is included in the section titled "Liquidity and Capital Resources". Tamarack and others utilize net debt and working capital deficiency (surplus) to assess liquidity and balance sheet strength by aggregating the select financial assets and financial liabilities on the Company's balance sheet.

Net debt to annualized adjusted funds flow

Net debt to annualized adjusted funds flow, is a capital management ratio and is calculated as net debt divided by the annualized adjusted funds flow for the most recently completed quarter. Tamarack and others utilize net debt to annualized adjusted funds flow to provide a snapshot of the overall financial health of the Company and assess the Company's ability to fund capital investments, acquisitions, the servicing of debt costs, debt reduction, the ability to raise new debt, repurchase shares or make dividend payments. The calculation of the Company's net debt to annualized adjusted funds flow is included in the section titled "Liquidity and Capital Resources".

Supplemental financial measures

Per share disclosures

Tamarack's supplementary financial measures on a per share basis consist of cash provided by operating activities per share and adjusted funds flow per share. These supplementary financial measures are determined by dividing the value of the financial measure by the weighted average common shares outstanding and diluted weighted average common shares outstanding, as presented in the Interim Financial Statements. The per share disclosures allow Tamarack and others to understand the value of the selected financial information attributable to each common share holder. Free funds flow per share is a non-GAAP financial ratio as discussed above.

Per BOE disclosures

Tamarack's supplementary financial measures on a per boe basis consist of average light oil realized sales price per bbl, average NGL realized sales price per bbl, average natural gas realized sales price per mcf, heavy oil differential including transportation expenses, light oil differential including transportation expenses, royalty expense per boe, transportation expenses per boe, carbon tax per boe, realized commodity hedging gain/loss per boe, G&A expense per boe, stock-based compensation expense per boe, cash interest expense per boe, finance expense per boe and DD&A per boe. The calculation of the heavy oil differential including transportation expenses and light oil differential including transportation expenses is included in the operating results section of this MD&A. Certain measures are presented on a per boe basis to allow Tamarack and others to assess the profitability of each barrel produced, and allows for a comparison of current period performance to historical periods, or to peer results, by isolating for the impact of differences in production volumes. Total revenue, net of blending expense per boe, net production expenses per boe, operating field netback per boe and operating netback per boe are non-GAAP financial ratios as discussed above.

Percentage of sales

Tamarack's supplementary financial measures as percentage of revenue consists of the average royalty rate. The average royalty rate as a percentage of sales, net of blending expense, is used by Tamarack and others to understand the average effective amount of royalties owing for each dollar of sales that is generated.

Disclosure controls and internal controls over financial reporting

Part 1 of *National Instrument 52-109 - Certification of Disclosure in Issuer's Annual and Interim Filings* defines disclosure controls and procedures ("DC&P") as "controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure".

The Company has designed DC&P to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in the annual filings, interim filings or other reports filed or submitted under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of annual financial statements for external purposes in accordance with IFRS Accounting Standards. The Company is required to disclose herein any change in the Company's ICFR that occurred during the recent fiscal period that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting.

No material changes to the Company's DCP and its ICFR were identified during the period ended September 30, 2024 that have materially affected, or are reasonably likely to affect, the Company's internal controls over financial reporting. As a result, the Company's DCP and ICFR were effective as at September 30, 2024. Internal control systems, including the Company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met, and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Volumetric reporting

For the purpose of reporting unit production and related units of measurement, natural gas volumes have been converted to a barrel of oil equivalent (boe) using six thousand cubic feet equal to one barrel. A boe conversion ratio of 6:1 is based on an energy equivalency conversion at the burner tip but does not necessarily represent a value equivalency at the wellhead where production is actually measured and reported. This conversion complies with the Canadian Securities Administrators' National Instrument 51–101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"), however, a Boe unit of measurement could be misleading, particularly if used in isolation.

Climate change

The Company continues to assess the impact of global demand for carbon-based energy and advancement of alternative energy sources. Emissions, carbon and other regulations impacting climate related matters are constantly evolving. With respect to ESG and climate reporting, the International Sustainability Standards Board ("ISSB") was created on November 3, 2021 to develop consistent, comparable and reliable sustainability disclosure standards. On June 26, 2023, the ISSB issued *IFRS S1 "General Requirements for Disclosure of Sustainability-related Financial Information*" and *IFRS S2 "Climate-related Disclosures*". *IFRS S1* and *IFRS S2* are effective for annual reporting periods beginning on or after January 1, 2024. The standards provide for transitional relief allowing an issuer to limit its disclosure to climate-related risks and opportunities in the first year.

The Canadian Securities Administrators ("CSA") are responsible for determining the reporting requirements for public companies in Canada and decisions related to the adoption of the sustainability disclosure standards, including the effective annual reporting dates. The CSA issued proposed National Instrument ("*NI 51-107 – Disclosure of Climate-related Matters*") in October 2021. The CSA has indicated it will consider the ISSB sustainability standards and developments in the United States in its decisions related to developing climate-related disclosure requirements for reporting issuers in Canada. The CSA will involve the Canadian Sustainability Standards Board ("CSSB") for their combined review of the ISSB issued sustainability standards for their suitability for adoption in Canada. Until such time as the CSA and CSSB make decisions on sustainability standard adoption in Canada, there is no requirement for public companies in Canada to adopt the sustainability standards. The Company is actively evaluating the potential effects of the sustainability standards.

Risks

Tamarack faces business risks, both known and unknown, with respect to its oil and gas exploration, development, and production activities that could cause actual results or events to differ materially from those forecasts. Most of these risks (financial, operational or regulatory) are not within the Company's control. While the following sections discuss some of these risks, they should not be construed as exhaustive. Tamarack is directly impacted by these risks:

- Volatility in commodity and petroleum product prices
- Inflation risk
- Environmental and climate change risk
- Financial risks
- Operational risks
- Regulatory risks

For additional information on the risks relating to Tamarack's business, see "Risk Factors" in Tamarack's Annual Information Form and "Business Risks" in Tamarack's Annual MD&A for the year ended December 31, 2023.

Forward-looking statements

Certain statements contained within this MD&A constitute forward-looking statements within the meaning of applicable Canadian securities legislation. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "budget", "plan", "endeavour", "continue", "estimate", "evaluate", "expect", "forecast", "monitor", "may", "will", "can", "able", "potential", "target", "intend", "consider", "focus", "identify", "use", "utilize", "manage", "maintain", "remain", "result", "cultivate", "could", "should", "believe", "strive" and similar expressions or the negative of such terms or other comparable terminology. The Company believes that the expectations reflected in such forward-looking statements are reasonable, but no assurance can be given that such expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. Without limitation, this MD&A contains forward-looking statements pertaining to:

- the intentions of management and the Company;
- the Company's commitment to maintaining financial flexibility and liquidity;
- the Company's business strategy, objectives, strength and focus, including with respect to acquisitions;
- the impacts on the Company of the military conflict between Russia and Ukraine as well as the war between Israel and Hamas;
- the Company's plans to continue developing two core projects in Northern Alberta – a Clearwater heavy oil position at Nipisi, Marten Hills and South Clearwater and a Charlie Lake light oil position at Valhalla, Wembley, and Pipestone;
- the Company's continued consideration of the impact of climate change and possible upcoming related financial and operational challenges and implications with respect to the future of the Company;
- the Company's continued consideration of the potential impacts of the evolving global demand for carbon-based energy and global advancement of alternative energy sources;
- expectations relating to future realized commodity prices, volatile commodity prices, royalty rates and oil price differentials and the effects thereof, including with respect to revenue, earnings and stability to oil pricing;
- the Company's financial and physical hedging program, including the use of financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates, and interest rates, and the effects thereof on cash flow risk and commodity pricing upside;
- anticipated benefits of Clearwater formations including its enhanced recovery potential;
- anticipated benefits of the Charlie Lake acreage;
- purchases under the Company's normal course issuer bid including that the Company will reacquire up to 54.6 million common shares by January of 2025;
- the Company's plans in respect of returns of capital, including dividend and enhanced return programs;
- the Company's expectations surrounding its 2024 capital program and funding thereof, including in relation to the ability to satisfy its 2024 & 2025 development capital program, dividend payments and any share repurchases;
- the Company's intent to direct the majority of the remaining free cash flow to net debt reduction and shareholder returns;
- expectations regarding the lower anticipated taxable emissions in 2024 and ability to continue carbon abatement initiatives;
- expectations surrounding the Credit Facility as amended and the terms thereof, including the extended maturity date and ability to access an incremental $125.0 million of secured debt subject to certain conditions;
- the Company's ability to maintain annual production guidance;
- financial covenants applicable to the Syndicated Facility;
- Tamarack's 2024 production guidance and ongoing assessments in respect of the same;
- commitments and obligations of the Company related to the Clearwater Infrastructure Partnership and pursuant to the definitive agreements entered into with 12 First Nation and Métis communities and the added 13th Indigenous community;
- expectations surrounding the Company's 2024 capital guidance and outlook, including that capital guidance balances maximizing free funds flow generation with a significant amount being directly towards shareholder returns;
- the Company's continued approach to capital allocation;
- the Company's ability to meet its obligations and commitments under the Senior Notes;
- the Company's head office sublease, as amended or extended, and the terms thereof;
- the Company's 2024 outlook and planned 2024 capital projects (including infrastructure expansions in the Clearwater area to support ongoing production growth, emissions reduction initiatives and the completion of certain strategic midstream facilities associated with the Clearwater Infrastructure Partnership);
- contractual obligations and commitments;
- estimates used to calculate decommissioning obligations and depletion of PP&E;
- expectations surrounding pre-tax net present value of Tamarack's 2P reserves;
- Tamarack's 2024 base capital investment guidance of $390 and $440 million and anticipated use thereof, being primarily focused on Clearwater and Charlie Lake drilling and development activities;
- Tamarack's plans to invest in secondary recovery expansion of Clearwater waterflood projects at Nipisi and Marten Hills;
- expectations surrounding Tamarack's gas conservation initiatives;
- the Company's risk management activities (including plans to continue actively managing capital and liquidity risk through continuous monitoring of asset performance, forecasting anticipated future cash flows in conjunction with the design of the annual capital investment programs, maintaining available credit under bank facilities, staggering debt maturity dates, hedging a portion of the Company's production, judiciously assessing new capital investment, acquisition or divestment opportunities and the pursuit of new liquidity, if necessary);
- the Company's plans in respect to its employees including for its employees to address the continued development of new or established reservoirs on a go-forward basis using the same procedure as is used to address exploration risk and the effects thereof on mitigation of operation risk;
- expectations surrounding the Company's major infrastructure projects and anticipated benefits thereof, including with respect to performance of its Clearwater and Charlie Lake drilling programs;
- expectations surrounding management's continued flexibility in respect of its second half capital program (including in relation to fluctuating commodity prices and management's monitoring thereof);
- expectations surrounding identified changes to the Company's DC&P and its ICFR (or lack thereof) and its affect on the Company's internal

controls over financial reporting on a go-forward basis (including the lack thereof);
- expectations regarding the merits and the outcome of ongoing litigation; and
- the Company's expectations regarding inflation and interest rates and the ability to manage such pressures.

With respect to the forward-looking statements contained in this MD&A, Tamarack has made assumptions regarding, among other things:

- future commodity prices, price differentials and the actual prices received for the Company's products;
- expected net production expenses and transportation expenses;
- estimated proved plus probable oil and natural gas reserves;
- the effects of heavy volume apportionment and fluctuating diluent costs on the heavy oil market in Alberta;
- the ability to obtain equipment and services in the field in a timely and efficient manner;
- the ability to add production and reserves through acquisition and/or drilling at competitive prices;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the realization of anticipated benefits of acquisitions, including the acquisitions and the related drilling programs;
- the ability to explore and realize benefits from exposure to diversified gas markets;
- drilling results, including field production rates and decline rates;
- the performance of the waterflood projects;
- the continued application of horizontal drilling and fracturing techniques and pad drilling;
- the continued availability of capital and skilled personnel;
- the ability to obtain financing on acceptable terms;
- the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation;
- the impact of increasing competition;
- the ability of the Company to secure adequate product transportation;
- the ability to enter into future commodity derivative contracts on acceptable terms;
- the continuation of the current tax, royalty and regulatory regime;
- the volatility in commodity prices and oil price differentials and the resulting effect on Tamarack's revenue, cash provided by operating activities, adjusted funds flows and earnings;
- the actions of OPEC and non-OPEC oil and gas exporting countries to set production levels and the influence thereof on oil prices and global demand including in respect of recent cuts to the group's production quotas;
- the ability to adjust capital spending relative to commodity prices and use financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates;
- Tamarack's ability to maintain financial flexibility; and
- the impact of inflation on costs and interest rates.

Without limitations 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.

Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated or implied by such forward-looking statements due to a number of factors and risks. These include:

- the material uncertainties and risks described under the heading "Advisories and guidance";
- the material assumptions and observations described under the headings "About Tamarack Valley Energy Ltd.", "Q3 2024 in review", "Q3 2024 operational and financial highlights", "Highlights for the three and nine months ended September 30, 2024", "Annual guidance", "Production", "Benchmark prices", "Oil and natural gas sales", "Risk management", "Royalties", "Net production expenses", "Transportation expenses", "Operating netback", "General and administrative ("G&A") expenses", "Stock-based compensation expense", "Finance expense", "Income taxes", "Depletion, depreciation and amortization ("DD&A")", "Adjusted funds flow and net income", "Investment in oil and natural gas assets", "Clearwater Infrastructure Partnership", "Dispositions", "Liquidity and capital resources" and "Selected quarterly information";
- the risks relating to inclement and severe weather events and natural disasters, including fire, drought and flooding and corresponding effects, including in respect to safety, asset integrity, shutting in production, impact on production, maintaining 2024 guidance and resumption of operations;
- the risks with respect to unplanned third-party pipeline or natural gas processing facility outages;
- the risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production and including continued weakness and volatility in commodity prices and petroleum product prices;
- the actions of OPEC and non-OPEC oil and gas exporting countries to set production levels and the influence on oil prices and global demand;
- Russia's military actions in Ukraine;
- the Israel-Hamas conflict;
- delays or changes in plans with respect to exploration or development projects or capital expenditures;
- volatility in market prices for oil and natural gas;
- uncertainties associated with estimating proved plus probable oil and natural gas reserves and the ability of the Company to realize value from its properties;
- geological, technical, drilling and processing problems;
- facility and pipeline capacity constraints and access to processing facilities and to markets for production;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- impact of the U.S. federal election and any related changes to the regulatory U.S. regime;
- uncertainties associated with timing of the next Canadian federal election, the successful party and any resulting changes on law or policy;
- credit worthiness of counterparties to commodity, foreign exchange and interest rate contracts;
- increased borrowing costs due to increased lending rates from prime rate increase, negative changes to financial metrics evaluated under the Credit Facility and Senior Notes sustainability performance targets;
- uncertainty regarding the full impact of pandemics on global economies and oil demand and commodity prices;
- marketing and transportation;
- prevailing weather and break-up conditions;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- net production costs, transportation and future development costs;
- the ability to access sufficient capital from internal and external sources;
- changes in tax, royalty and environmental legislation and any government policy, including Bill C-59;
- any legal proceedings, the results thereof and the impact on the Company's business, financial condition and results of operations;
- third party inability to manage inflationary cost pressures;
- changes in the political landscape, both domestically and abroad; and

- increased operating and capital costs due to inflationary pressures (actual and anticipated).

Readers are cautioned that the foregoing list of risk factors is not exhaustive. The risk factors above should be considered in the context of current economic conditions, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also, to be considered are increased levels of political uncertainty and possible changes to existing international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company's business. Additional information on these and other factors that could affect the business, operations or financial results of Tamarack are included in reports on file with applicable securities regulatory authorities, including but not limited to Tamarack's Annual Information Form for the year ended December 31, 2023, which may be accessed on Tamarack's SEDAR+ profile www.sedarplus.com or on the Company's website at www.tamarackvalley.ca.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Tamarack's 2024 and 2025 development capital program and plans regarding payment of 2024 dividends and any share repurchases by using available increased credit facilities combined with anticipated adjusted funds flow, commodity prices, Tamarack's 2024 capital guidance and components thereof including prospective results of operations and production, planned investment in oil and natural gas assets; expected capital expenditures (including in respect of Tamarack's capital E&D budget), 2024 annual guidance and the components thereof including capital investments and annual average production, average oil & NGL weighting, and expenses (including expected royalty rates, net production expenses, transportation expenses, leasing expenditures, carbon tax, G&A expenses, interest and income taxes), payout of wells, adjusted funds flow, net debt (and the reduction thereof), capital requirements, return of capital, balance sheet strength, the Company's 2024 budget and associated targets, debt repayments, Tamarack's 2024 base capital investment program of $440 million, targeting average production range of 63,000-64,000 boe per day in 2024 at Clearwater and Charlie Lake development areas, expected commitments and contingencies of the Company over the upcoming years and the components thereof, total returns and components thereof, decline rates, netback enhancement from blending, 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 under "Non-GAAP Financial Measures and Non-GAAP Financial Ratios" and "Capital Management Measures and Ratios", and should not be used for purposes other than those for which it is disclosed herein. Tamarack and its management believe that the prospective financial information 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, Tamarack's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future activities or results.

The forward-looking statements and FOFI contained in this MD&A, as defined by Canadian securities legislation, are approved by management as of the date hereof and Tamarack undertakes no obligation to update publicly or revise any forward-looking statements, forward-looking information or FOFI whether as a result of new information, future events or otherwise, unless so required by applicable securities laws. The forward-looking statements and FOFI contained herein are expressly qualified by this cautionary statement.

Note regarding product types
This MD&A includes references to total average daily production, crude oil production, NGLs production and natural gas production. NGLs refers to all natural gas liquids, consisting of condensate, pentanes plus, butane, propane and ethane. Natural gas refers to conventional natural gas and shale gas combined. Crude oil refers to light, medium, and heavy crude oil combined.

Reserves Disclosure
All references to reserves are presented on a gross basis, reflecting Tamarack's working interest before royalties. The figures are based on the independent evaluation reports of McDaniel and GLJ, dated February 9, 2024 and January 29, 2024, respectively, and have an effective date of December 31, 2023. The reports were prepared in accordance with National Instrument 51-101 and the Canadian Oil and Gas Evaluations Handbook and contain significant estimates, assumptions and judgements relating to crude oil and natural gas reserves, production, commodity prices, future development costs and operating related expenses. These reports are subject to significant measurement uncertainty as actual results may differ from these estimates and could be material.

Abbreviations

AECO	Alberta Energy Company benchmark for natural gas
Bbl(s)	barrel(s)
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
CGU	Cash-generating unit
EOR	Enhanced oil recovery
ESG	Environment, sustainability and governance
GHG	Greenhouse gas emissions
GJ	gigajoule
GJ/d	gigajoule per day
IFRS	IFRS Accounting Standards
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbtu	one million British thermal units
mmbtu/d	one million British thermal units per day
MSW	mixed sweet blend, the benchmark for conventionally produced light sweet crude oil in Western Canada
NCWC	non-cash working capital
NGL	natural gas liquids
nm	not meaningful information
NYMEX	New York Mercantile Exchange
PP&E	Property, plant and equipment
TP	total proved reserves
TPP	total proved plus probable reserves
WCS	Western Canadian Select, the benchmark for both conventionally produced and oilsands produced heavy sour crude oil in Western Canada
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma