

2024

ANNUAL INFORMATION FORM



ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2024
DATED FEBRUARY 24, 2025



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APPENDIX “A” FORM 51-101F2 REPORT OF RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

APPENDIX “B” FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

APPENDIX “C” AUDIT COMMITTEE MANDATE

The information in this Annual Information Form (“AIF”) is given as of December 31, 2024 unless otherwise indicated.

TAMARACK VALLEY ENERGY LTD.

COMPANY BACKGROUND

Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") is a corporation engaged in the exploration, development, production and sale of oil and natural gas in the Western Canadian Sedimentary Basin.

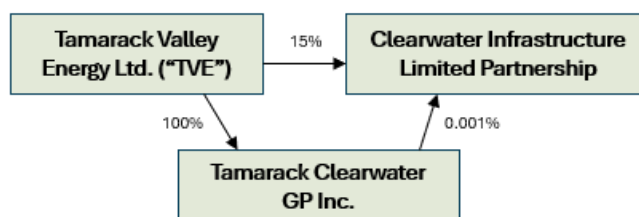
Tamarack is based in Calgary, Alberta and was incorporated under the Business Corporations Act (Alberta) on March 6, 2002 as a "capital pool company" (as defined in the TSX Venture Exchange ("TSX-V") Corporate Finance Manual (the "Manual")) and possessed no assets. In November 2002, the Company acquired all the issued and outstanding shares of Dunhaven Energy Inc. by way of a take-over bid for consideration of \$670,000, which constituted the Company's "qualifying transaction" (as defined in the Manual).

On June 17, 2010, the Company completed a restructuring transaction, which included the amalgamation of a privately held entity with a subsidiary of the Company, the reconstitution of the Board of Directors, the appointment of a new management team led by Brian Schmidt, and a change of name of the Company from "Tango Energy Inc." to "Tamarack Valley Energy Ltd."

Tamarack is a reporting issuer in each of the provinces of Canada. The Common Shares have traded on the Toronto Stock Exchange under the symbol "TVE" since August 24, 2015. Previously, the Common Shares were trading on the TSX-V. The Company's head office is located at Suite 1700, 525 – 8th Avenue S.W. Calgary, Alberta, T2P 1G1. The registered office of the Company is located at Suite 4300, 888 – 3rd Street S.W., Calgary, Alberta, T2P 5C5.

INTER-CORPORATE RELATIONSHIPS

The following diagram presents the corporate structure of Tamarack and its material subsidiaries as at December 31, 2024 and the date of this AIF.



On December 13, 2023, Tamarack and 12 First Nation and Métis communities formed the Clearwater Infrastructure Limited Partnership. On September 17, 2024, Tamarack Clearwater Infrastructure Partnership was expanded to include a 13th Indigenous community.

GENERAL DEVELOPMENTS OF THE BUSINESS

Developments in 2025

- On February 12, 2025, Tamarack issued a 2024 reserves and operational update. As at December 31, 2024, the Company's total gross proved and probable reserves⁽²⁾ were 238.3 million boe, a 6% increase compared to 224.3 million boe in the prior year. The increase was primarily due to reserve additions through ongoing drilling and development activities at Clearwater and Charlie Lake, partially offset by the sale of the Company's Redwater and Penny Banff assets and associated production in the year. Tamarack's proved plus probable reserves are estimated to have a pre-tax net present value of approximately \$5.14 billion⁽²⁾ using a 10% discount rate.
- On January 14, 2025, the Company renewed its normal course issuer bid, allowing Tamarack to purchase up to 51.3 Common Shares of the Company over a 12-month period ending January 18, 2026.

Developments in 2024

- During the year ended December 31, 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 those dispositions, Tamarack reduced its asset retirement obligations by \$18.7 million. In December, Tamarack also entered into a purchase and sale agreement for the disposition of certain non-core oil and natural gas in Southern Alberta for gross cash proceeds of \$28.0 million before closing adjustments and is expected to close in the second quarter of 2025, subject to the receipt of third-party regulatory approval. As at December 31, 2024, the net assets were presented as held for sale at the anticipated recoverable value resulting in an impairment loss of \$38.1 million. As part of the sale, asset retirement obligations are expected to be reduced by \$14.3 million.
- Tamarack's 2025 corporate budget was announced on December 4, 2024. The budget included a production forecast of 65,000 to 67,000 boe per day and capital expenditures of \$430-\$450 million, focusing on free funds flow generation from the Clearwater and Charlie Lake oil plays in support of ongoing returns to shareholders.

- On October 31, 2024, Tamarack announced a 2% increase in its monthly dividend to \$0.01275 per share.
- On September 17, 2024, the Company expanded the Clearwater Infrastructure Limited Partnership to include a 13th Indigenous Community to the arrangement through the contribution of additional Clearwater infrastructure assets, receiving gross cash proceeds of \$43.2 million. In exchange, Tamarack assumed higher fees on the pre-existing 16-year take-or-pay. The committed volumes did not change, and all other material terms of the original agreement were retained under the expansion.
- In June 2024, Tamarack's net debt declined to within the \$500 million - \$900 million range, thereby achieving the Company's second net debt threshold within its pre-established return of capital framework and accelerating the opportunity for additional share buybacks subject to the availability of future free funds flow.
- Mr. Rene Amirault was appointed to the Company's Board of Directors effective June 14, 2024.
- On May 8, 2024, Mr. Jeffrey Boyce and Ms. Kathleen Hogenson did not stand for re-election to the Board of Directors.
- On May 3, 2024, Tamarack's Credit Facility was amended primarily to extend the maturity date of the facility by one year to April 30, 2027. Tamarack also added an uncommitted accordion feature that provides the Company with the ability to access an incremental \$125.0 million of secured debt, subject to certain conditions including approval from the lending syndicate.
- In March 2024, Tamarack repaid the remaining outstanding balance of the term loan (\$83.5 million) and DAP Notes (\$56.7 million) primarily utilizing proceeds from draws under the Credit Facility.
- Ms. Rocky Baker was appointed VP, Marketing effective February 28, 2024.
- Ms. Shannon Joseph was appointed to the Company's Board of Directors effective February 1, 2024.
- On January 16, 2024, Tamarack announced that the Company achieved its first debt threshold within its return of capital framework, accelerating the initiation of enhanced returns. The Company renewed its normal course issuer bid, allowing Tamarack to purchase up to 54.6 million Common Shares of the Company over a period of twelve months ending on January 18, 2025. For the year ended December 31, 2024, Tamarack acquired 33.9 million shares for gross proceeds of \$135.4 million, including applicable income taxes.

Developments in 2023

- On December 15, 2023, Tamarack and 12 First Nations and Métis communities completed a series of definitive agreements whereby the Indigenous Communities acquired an 85% non-operating working interest in the newly formed Clearwater Infrastructure Limited Partnership. Pursuant to the arrangement, Tamarack transferred certain Clearwater midstream assets with a fair value of \$172.0 million to the Partnership for consideration of \$131.2 million cash, a promissory note of \$15.0 million and a 15% operating working interest. Tamarack assumed a 16-year take-or-pay commitment for 29,000 boe/d and is responsible for all associated operating and maintenance costs. The Company has also retained full access to 100% of Tamarack's existing 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.
- Tamarack's 2024 corporate budget was announced on December 6, 2023. A base budget of 61,000 to 63,000 boe per day and growth budget of 61,000 to 64,000 boe per day were released, focusing on free funds flow generation from the Clearwater and Charlie Lake oil plays.
- On November 3, 2023, the Company sold its non-core west central Alberta assets for gross cash proceeds of \$123.0 million (net proceeds of \$98.9 million). As part of the disposition, Tamarack reduced asset retirement obligations by \$75.3 million. Following the sale of the natural gas-weighted assets, ~90% of the Company's total production was from the Clearwater and Charlie Lake oil plays. The sale was announced on October 19, 2023, with the appointment of Mr. Kevin Johnston as Vice President, Finance.
- On July 31, 2023, the Company issued a gross overriding royalty (between 2% and 5%) on select portions of its Clearwater and Charlie Lake oil properties and sold a working interest in the Wembley gas plant for gross cash proceeds of \$39.5 million.
- On May 10, 2023, the Company's credit facility was increased from \$700 million to \$875 million and the maturity date was extended to May 10, 2026.
- Ms. Caralyn Bennett was appointed to the Company's Board of Directors effective March 1, 2023.
- On January 19, 2023, the Company implemented a normal course issuer bid, allowing Tamarack to purchase up to 27.8 million of its Common Shares over the 12-month period ending January 18, 2024. There were no share buybacks completed in 2023.

Developments in 2022

- Effective October 13, 2022, Mr. Ian Currie resigned as a member of the Board of Directors and Ms. Kathleen Hogenson was appointed to the Board. Ms. Lynne Chrumka was appointed VP, Exploration.
- On October 13, 2022, the Company closed its acquisition of Deltastream Energy Ltd. for total consideration of \$1.425 billion, comprised of 80 million Common Shares of Tamarack, \$300 million of deferred acquisition payment notes and \$825 million in cash. The Company also increased its existing credit facility to \$700 million, paired with a \$260 million two-year secured amortizing term-loan from a syndicate of lenders. The acquisition was also funded in part by the transactions previously announced on September 22, 2022 and September 27, 2022.
- On September 27, 2022, Tamarack closed a bought deal prospectus offering of 33,334,000 Common Shares at a price of \$3.75 per Common Share for aggregate gross proceeds of \$125 million. In addition, the over-allotment option granted to underwriters

was exercised in full for an additional 5,000,100 Common Shares and additional gross proceeds of \$19 million, for total gross proceeds of \$144 million.

- On September 22, 2022, Tamarack closed a private placement offering of \$100 million aggregate principal amount of 7.25% senior unsecured notes due May 2027. The senior notes were issued under a trust indenture pursuant to which the Company previously issued \$200 million of senior notes in February 2022, with a supplemental indenture dated September 22, 2022.
- On September 12, 2022, Tamarack announced a 25% increase in its monthly dividend to \$0.0125 per share.
- On July 28, 2022, Mr. Martin Malek resigned as Vice President, Engineering and Mr. Ben Stoodley was appointed Vice President, Engineering.
- On July 21, 2022, Tamarack closed the disposition of non-core Viking assets for total consideration of \$57.9 million.
- On June 10, 2022, the Company completed the acquisition of Rolling Hills Energy Ltd. (“Rolling Hills”) a privately held Clearwater oil producer for aggregate consideration of \$93 million, including 9.3 million Common Shares of Tamarack and \$46.5 million in cash. Concurrent with the acquisition, Tamarack announced that its credit facility has been extended to May 31, 2024 and increased to \$650 million.
- On April 21, 2022, Tamarack announced a 20% increase in its monthly dividend to \$0.010 per share.
- On February 15, 2022, Tamarack completed the acquisition of Crestwynd Exploration Ltd., a privately held Clearwater oil producer, for aggregate consideration of \$184.7 million, including \$92.6 million cash and 26.3 million TVE Common Shares.
- On February 10, 2022, Tamarack closed the private placement financing for \$200 million of senior unsecured notes.
- On January 13, 2022, the Company declared an inaugural monthly dividend of C\$0.0083 per share on its issued and outstanding Common Shares in accordance with its new dividend policy and program. See “Dividends”.

Significant Acquisitions

- The acquisition of Deltastream Energy Ltd., completed on October 13, 2022, constituted a significant acquisition under Part 8 of National Instrument 51-102 – Continuous Disclosure Obligations. The Company filed a Form 51-102F4 (Business Acquisition Report) in respect of the acquisition on November 15, 2022. The report is available at www.sedarplus.ca.
- On June 10, 2022, Tamarack closed the acquisition of Rolling Hills Energy Ltd. a privately held Clearwater oil producer. A Form 51-102F3 Material Change Report in respect of the acquisition of Rolling Hills was filed on SEDAR+.
- On February 15, 2022, Tamarack closed the acquisition of Crestwynd, a privately held Clearwater oil producer. A Form 51-102F3 Material Change Report in respect of the acquisition of Crestwynd was filed on SEDAR+.

DESCRIPTION OF THE BUSINESS

Business Objectives and Strategy

Tamarack 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 a diverse enhanced oil recovery portfolio of assets across Alberta.

As of December 31, 2024, the Company held over 680 sections of acreage across the Clearwater fairway with 134.5 million boe of total gross proved plus probable reserves. 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 2024.

Tamarack also holds over 240 sections of Charlie Lake acreage with 70.8 million boe of total gross proved plus probable reserves 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 (68% liquids) from Charlie Lake in 2024.

Since 2010, Tamarack has evolved from a Cardium-focused, junior exploration and production company to an intermediate Clearwater, Charlie Lake and enhanced-oil-recovery player. The Clearwater and Charlie Lake assets provide exposure to some of the most economic oil plays in Western Canada. Through multiple accretive acquisitions and successful delineation, Tamarack has assembled an extensive inventory of low-risk oil development drilling locations. With this portfolio, Tamarack is committed to creating long-term value for its shareholders through sustainable free funds flow generation, financial stability, pursuit of profitable growth and the return of capital.

As part of this transformation, Tamarack has divested a number of non-core oil and natural gas assets primarily to reduce net debt following the acquisitions in 2021 and 2022 and to reduce asset retirement obligations particularly on lower productivity assets. In doing so, the Company has created a strong financial foundation for future development and growth of the Company’s top-tier Clearwater and Charlie Lake asset areas. Tamarack has also formed a partnership with 13 Indigenous Communities in the Clearwater area in order to provide the Company with a unique and long-term source of secured financing while fostering strong relationships with local stakeholders and enhancing economic prosperity in the region.

Tamarack has established a long-term development plan that is funded through internally generated cash flows and is expected to generate free funds flow across a wide range of commodity price environments. The Company seeks to develop high-quality assets

by executing a technically disciplined, full-cycle approach to oil and natural gas exploration and development along with the continued adoption of new technologies to improve efficiencies.

Tamarack evaluates new opportunities by following a disciplined methodology of integrating technical information with expected economic outcomes and risking the expected value of each opportunity according to the existing producing analogs in a particular area. The Company employs screening criteria to evaluate prospective areas for repeatability and scope. Tamarack believes that this disciplined approach will continue to yield consistent results over the long-term. Tamarack may pursue acquisitions or divestitures where opportunities exist to enhance the overall value of the organization. The Company intends to maintain its low cost and efficient structure, both in the field and in the general management of the business. Tamarack believes that maintaining cost-efficient operations and a strong balance sheet will ensure it is well positioned to manage through all commodity price cycles.

Tamarack is dedicated to ensuring the health, safety and wellness of staff, partners and communities where it works. The Company promotes a culture that prioritizes safety, risk mitigation and continuous education of safety protocols.

Specialized Skills and Knowledge

The Company's business requires the application of high levels of technical skill in the areas of marketing, geology, geophysics, engineering, drilling and completions, well production operations and finance. Drawing on a depth of experience in the oil and natural gas business, Tamarack's team has a demonstrated track record of bringing together all of the key components necessary to run a successful development and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; capital markets expertise; and an entrepreneurial spirit that allows Tamarack to effectively identify, evaluate and execute on value-added initiatives.

Exploration Risk Management

Exploration drilling involves substantial risk and there are no assurance that drilling will prove successful in establishing commercially recoverable reserves. While Tamarack believes the Company has the necessary skillsets and resources to achieve its objectives, participation in the exploration and development of oil and natural gas has a number of inherent risks. See "Risk Factors" for a discussion of exploration risk.

Cyclical and Seasonal Impact

Tamarack's operational results and financial condition are heavily impacted by market-based commodity prices which is largely beyond the Company's control. Oil and natural gas prices fluctuate widely and are affected by supply and demand factors, weather, general economic conditions and regional political conflicts, both locally and abroad. Any decline in oil and natural gas prices could have an adverse effect financial condition. Tamarack seeks to mitigate a portion of that commodity price risk with active marketing and hedging programs to support the netbacks on production volumes. See "Statement of Reserves Data and Other Oil and Natural Gas Information – Forward Contracts" for information regarding the Company's current hedging program.

Competitive Environment

Tamarack operates in a highly competitive environment. The Company actively competes for reserve acquisitions, exploration leases, licences, concessions, access to commodity markets, access to service providers, field equipment, debt and equity capital markets, employees and skilled industry personnel with a substantial number of energy companies, many of which have greater financial resources than Tamarack. Competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies. The Company believes that the experience brought by the management team enables Tamarack to compete with its peers and industry competitors. The Company also maintains strong relationships with industry partners and joint operators which can help facilitate and consummate potential transactions or other opportunities.

Environmental Policies and Responsibility

The oil and natural gas industry is subject to environmental regulations pursuant to provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of these requirements may result in suspension or revocation of licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness. Tamarack is committed to meeting its responsibilities to protect the environment and ensure compliance with all regulatory authorities.

Employees

As at December 31, 2024, Tamarack employed 103 full time individuals and 14 full time equivalent consultants at the head office in Calgary, Alberta. The Company also employed seven full time field employees and 171 full time equivalent contract field staff located at various field offices in Alberta.

Economic Diversity

Tamarack pursues economic diversity by avoiding dependence on any single contract or license, such as a contract to sell a major part of its products or services or to purchase most of its goods, services or raw materials.

Change to Contracts

Tamarack does not reasonably anticipate being materially affected by renegotiation or termination of contracts.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Tamarack retained two qualified reserves evaluators to provide an independent evaluation of the Company's Proved Reserves and Proved plus Probable Reserves: (i) McDaniel & Associates Consultants Ltd. ("McDaniel") was appointed to evaluate the Company's Clearwater assets; (ii) GLJ Ltd. ("GLJ") was appointed to evaluate the Company's Charlie Lake and other enhanced oil recovery asset areas. Tamarack's statements of reserves data and other oil and gas information with an effective date of December 31, 2024 are based on the reports of McDaniel and GLJ, dated January 20, 2025 and January 8, 2025, respectively.

These independent reserve evaluation reports have been prepared in accordance with the *Canadian Oil and Gas Evaluation Handbook* and National Instrument 51-101 - *Standards of Disclosures for Oil and Gas Activities*. The reports were based on the data provided by Tamarack (except for certain information residing in the public domain) and was accepted by the reserve engineers as presented without investigation or field inspection. The tables set forth below contain reserves information from the McDaniel and GLJ reports that have been consolidated for reporting purposes. Figures may not add due to rounding.

There are significant estimates, assumptions, judgements and uncertainties inherent in the estimation of crude oil, NGL and conventional natural gas reserves and their associated future cash flows. Estimates include forecasts for production and recovery factors, commodity prices, production costs, royalty rates, future development costs, and future laws and regulations. These estimates are subject to change and may vary materially from actual results. The advancement of a global transition to alternative energy, is another source of uncertainty and could impact key estimates and assumptions regarding the measurement of these reserve evaluations. Readers should not assume that these evaluations reflect the fair market value of Tamarack's reserves and there are no assurances that the forecasts will be achieved.

Refer to the *Report on Reserves Data by Independent Qualified Reserves Evaluators or Auditors* in Form 51-101F2 and the *Report of Management and Directors on Oil and Gas Disclosure* in Form 51-101F3 are attached in Appendices "A" and "B", respectively.

SUMMARY OF OIL AND GAS RESERVES AS OF DECEMBER 31, 2024 FORECAST PRICES AND COSTS

Reserves Category	Light & Medium Crude Oil Gross	Light & Medium Crude Oil Net	Heavy Crude Oil Gross	Heavy Crude Oil Net	Natural Gas Gross	Natural Gas Net	Natural Gas Liquids Gross	Natural Gas Liquids Net	Total Gross	Total Net
	(MBbl) ⁽¹⁾	(MBbl) ⁽¹⁾	(MBbl)	(MMbl)	(MMcf)	(MMcf)	(MBbl) ⁽²⁾	(MBbl) ⁽²⁾	(MBoe)	(MBoe)
Proved:										
Developed Producing	17,153	13,124	39,314	31,726	60,342	54,639	2,724	2,168	69,248	56,125
Developed Non-Producing	2,012	1,613	242	217	5,241	4,809	341	286	3,469	2,917
Undeveloped	18,367	14,666	36,422	30,705	45,810	41,396	2,505	2,061	64,930	54,331
Total Proved	37,531	29,402	75,978	62,648	111,393	100,843	5,571	4,515	137,647	113,373
Probable	32,350	24,222	47,621	37,650	93,082	83,167	5,125	3,978	100,610	79,710
Total Proved plus Probable	69,881	53,624	123,600	100,297	204,476	184,010	10,696	8,494	238,256	193,083

(1) Immaterial Tight Oil volumes have been included with Light & Medium Crude.

(2) Condensate volumes are included in Natural Gas Liquids.

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES AS OF DECEMBER 31, 2024 DISCOUNTED AT % PER YEAR

Reserves Category	0% (\$000)	5% (\$000)	10% (\$000)	15% (\$000)	20% (\$000)	(\$/Mcf) ⁽¹⁾	(\$/Boe) ⁽¹⁾
Proved:							
Developed Producing	2,235,820	2,059,394	1,887,298	1,738,207	1,612,080	5.60	33.63
Developed Non-Producing	110,205	94,803	82,850	73,597	66,326	4.73	28.40
Undeveloped	1,724,779	1,343,771	1,058,014	843,062	679,250	3.25	19.47
Total Proved	4,070,804	3,497,968	3,028,161	2,654,866	2,357,656	4.45	26.71
Probable	3,782,910	2,771,333	2,113,503	1,670,595	1,360,634	4.42	26.51
Total Proved plus Probable	7,853,713	6,269,301	5,141,665	4,325,462	3,718,291	4.44	26.63

(1) Unit values are based on the Company's pre-tax net present values discounted at 10% using net reserves.

**NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES
AS OF DECEMBER 31, 2024 DISCOUNTED AT % PER YEAR**

Reserves Category	0% (\$000)	5% (\$000)	10% (\$000)	15% (\$000)	20% (\$000)	(\$/Mcf) ⁽¹⁾	(\$/Boe) ⁽¹⁾
Proved:							
Developed Producing	1,906,554	1,758,475	1,608,333	1,476,693	1,364,707	4.78	28.66
Developed Non-Producing	85,660	73,127	63,621	56,328	50,627	3.64	21.81
Undeveloped	1,315,235	1,008,708	778,168	605,846	475,813	2.39	14.32
Total Proved	3,307,449	2,840,310	2,450,121	2,138,867	1,891,147	3.60	21.61
Probable	2,926,620	2,132,150	1,615,589	1,269,335	1,028,337	3.38	20.27
Total Proved plus Probable	6,234,069	4,972,460	4,065,711	3,408,202	2,919,484	3.51	21.06

(2) Unit values are based on the Company's after-tax net present values discounted at 10% using net reserves.

**TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2024 FORECAST PRICES AND COSTS**

Reserves Category	Revenue ⁽¹⁾ (\$000)	Royalties ⁽²⁾ (\$000)	Operating Costs (\$000)	Capital Abandonment		Future Net	Future Net	
				Development	& Reclamation	Revenue	Income Tax	Income Tax
				Costs (\$000)	Costs (\$000)	Before	(\$000)	After
						Income Tax		Income Tax
						(\$000)		(\$000)
Total Proved	10,903,044	2,022,545	3,242,585	1,273,443	293,666	4,070,804	763,355	3,307,449
Total Proved plus Probable	19,383,026	3,878,033	5,485,069	1,812,763	353,448	7,853,713	1,619,645	6,234,069

(1) Includes all product revenues and other revenues as forecast.

(2) Royalties include any net profits interests paid.

**FUTURE NET REVENUE BY PRODUCTION TYPE AS OF DECEMBER 31, 2024
FORECAST PRICES AND COSTS**

Reserves Category	Production Type ⁽¹⁾	Net Revenue	Unit Value	Unit Value
		Before Taxes	(\$/Mcf) ⁽²⁾	(\$/Boe) ⁽²⁾
		@ 10% (\$000)		
Total Proved	Light and Medium Oil	881,498	5.00	29.98
	Heavy Oil	2,162,882	5.75	34.52
	Conventional Natural Gas	(16,219)	(0.16)	(0.96)
	Total	3,028,161	4.45	26.71
Proved plus Probable	Light and Medium Oil	1,753,498	5.45	32.70
	Heavy Oil	3,405,148	5.66	33.95
	Conventional Natural Gas	(16,981)	(0.09)	(0.55)
	Total	5,141,665	4.44	26.63

(1) Light and medium oil values include solution gas and other by-products and includes immaterial tight oil volumes. Conventional natural gas values include by-products but exclude solution gas.

(2) Unit values are based on Company net reserves and are calculated using the 10% discount rate divided by the Major Product Type Net reserves for each group. Total Company unit values estimated from the McDaniel and GLJ evaluations assuming unit values from both evaluators use Major Product Type Net reserves as the denominator in the calculation.

**RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS⁽¹⁾**

	Light & Medium	Light & Medium	Light & Medium	Heavy Crude	Heavy Crude	Heavy Crude	Total Crude	Total Crude	Total Crude
	Crude Oil	Crude Oil	Crude Oil						
	Proved	Probable	Proved + Probable	Oil Proved	Oil Probable	Oil Proved + Probable	Oil Proved	Oil Probable	Oil Proved + Probable
	(MBbl)	(MBbl)	(MBbl)	(MBbl)	(MBbl)	(MBbl)	(MBbl)	(MBbl)	(MBbl)
December 31, 2023	42,036	34,979	77,015	62,025	42,343	104,368	104,060	77,322	181,382
Discoveries	-	-	-	-	-	-	-	-	-
Extensions & Improved Recovery ⁽²⁾	1,675	1,988	3,664	16,903	6,564	23,466	18,578	8,552	27,130
Technical Revisions	889	(2,148)	(1,259)	10,883	(1,466)	9,417	11,772	(3,614)	8,157
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(1,860)	(2,485)	(4,345)	-	-	-	(1,860)	(2,485)	(4,345)
Economic Factors	15	15	30	106	181	287	121	197	317
Production	(5,223)	-	(5,223)	(13,938)	-	(13,938)	(19,161)	-	(19,161)
December 31, 2024	37,531	32,350	69,881	75,978	47,621	123,600	113,510	79,971	193,481

	NGL Proved (MBbl)	NGL Probable (MBbl)	NGL Proved + Probable (MBbl)	Natural Gas Proved ⁽⁴⁾ (MMcf)	Natural Gas Probable (MMcf)	Natural Gas Proved + Probable (MMcf)	Total Proved (MBoe)	Total Probable (MBoe)	Total Proved + Probable (MBoe)
December 31, 2023	5,095	4,322	9,417	112,046	88,822	200,869	127,830	96,448	224,277
Extensions & Improved Recovery ⁽²⁾	510	285	795	13,848	10,151	23,999	21,396	10,529	31,925
Discoveries	-	-	-	-	-	-	-	-	-
Technical Revisions	906	519	1,424	6,986	(5,606)	1,381	13,842	(4,030)	9,812
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	(683)	(253)	(936)	(1,973)	(2,528)	(4,501)
Economic Factors	(5)	-	(5)	(114)	(32)	(147)	97	191	288
Production	(935)	-	(935)	(20,690)	-	(20,690)	(23,545)	-	(23,545)
December 31, 2024	5,571	5,125	10,696	111,393	93,082	204,476	137,647	100,610	238,256

(1) Company Gross Reserves exclude royalty volumes.

(2) Reserves additions under Infill Drilling, Improved Recovery and Extensions are combined and reported as "Extensions and Improved Recovery".

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS AS OF DECEMBER 31, 2024
FORECAST PRICES AND COSTS

Year	Crude Oil WTI Cushing Oklahoma 40° API (US\$/Bbl)	Crude Oil Edmonton Par Price 40° API (C\$/Bbl)	Crude Oil Hardisty Bow River 25° API (C\$/Bbl)	Crude Oil Western Canadian Select (C\$/Bbl)	Natural Gas AECO/NIT Spot (C\$/Mmbtu)	NGL Edmonton Propane (C\$/Bbl)	NGL Edmonton Butane (C\$/Bbl)	NGL Edmonton C5+ (C\$/Bbl)	Inflation Rate (%/Year)	Exchange Rate (US\$/C\$)
2025	71.58	94.79	83.89	82.69	2.36	33.56	51.15	100.14	-	0.7117
2026	74.48	97.04	86.45	84.27	3.33	32.78	49.99	100.72	2	0.7283
2027	75.81	97.37	85.50	83.81	3.48	32.81	50.16	100.24	2	0.7433
2028	77.66	99.80	87.21	85.70	3.69	33.63	51.41	102.73	2	0.7433
2029	79.22	101.79	88.95	87.45	3.76	34.30	52.44	104.79	2	0.7433
2030	80.80	103.83	90.73	89.25	3.83	34.99	53.49	106.86	2	0.7433
2031	82.42	105.91	92.55	91.04	3.91	35.69	54.56	109.01	2	0.7433
2032	84.06	108.03	94.40	92.85	3.99	36.40	55.65	111.19	2	0.7433
2033	85.74	110.19	96.29	94.71	4.07	37.13	56.76	113.42	2	0.7433
2034	87.46	112.39	98.21	96.61	4.15	37.87	57.90	115.69	2	0.7433
2035	89.21	114.64	100.18	98.54	4.23	38.63	59.05	118.00	2	0.7433
2036	90.99	116.93	102.18	100.51	4.32	39.40	60.24	120.36	2	0.7433
2037	92.81	119.27	104.22	102.52	4.40	40.19	61.44	122.77	2	0.7433
2038	94.67	121.65	106.31	104.57	4.49	41.00	62.67	125.23	2	0.7433
2039	96.56	124.09	108.43	106.66	4.58	41.82	63.92	127.73	2	0.7433
2040+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr		

The information included in the pricing table above is based on an average of pricing assumptions prepared by two independent external reserves evaluators. Tamarack's weighted average realized sales prices for the year ended December 31, 2024 were \$96.12/Bbl for light and medium crude oil, \$82.59/Bbl for heavy oil, \$37.51/Bbl for NGL and \$1.72/Mcf for natural gas. The average realized price on a total oil equivalent basis was \$73.08/Boe.

PROVED UNDEVELOPED RESERVES FIRST ATTRIBUTED 2022 - 2024 (\$'000)
FORECAST PRICES AND COSTS

Year	Light & Medium Crude Oil First Attributed (MBbl) ⁽¹⁾	Light & Medium Crude Oil at Year-End (MBbl)	Heavy Crude Oil First Attributed (MBbl) ⁽¹⁾	Heavy Crude Oil at Year-End (MBbl)	Natural Gas First Attributed (MMcf) ⁽¹⁾	Natural Gas at Year-End (MMcf)	Natural Gas Liquids First Attributed (MBbl) ⁽¹⁾	Natural Gas Liquids at Year-End (MBbl)	Total First Attributed (MBoe) ⁽¹⁾	Total at Year-End (MBoe)
2022	2,284	23,246	17,237	18,557	12,438	64,100	682	4,001	22,275	56,488
2023	1,126	21,732	14,361	29,120	7,853	50,109	286	2,435	17,081	61,639
2024	1,003	18,367	13,144	36,422	7,916	45,810	314	2,505	15,781	64,930

(1) Refers to reserves first attributed in this fiscal year ending on the effective date.

Undeveloped Reserves are attributed by McDaniel and GLJ in accordance with the standards and procedures contained in the COGE Handbook. Proved undeveloped reserves (“PUD”) reserves are generally those reserves related to drilling spacing units directly offsetting producing reserves where there is demonstrated geological continuity. The majority of the PUD reserves are forecast for development over the next four years. McDaniel and GLJ have forecasted the Company to spend approximately 58% of its TP future development capital (“FDC”) in 2025 and 2026. In 2027, 25% of the Company’s TP FDC is expected to be invested, with approximately 17% remaining to be invested in the subsequent two years. Tamarack expects that 99% of the TP FDC forecast by McDaniel and GLJ will be invested within five years. The Company believes this allocation of capital investment and development of reserves is reasonable and is consistent with historical practices.

PROBABLE UNDEVELOPED RESERVES FIRST ATTRIBUTED 2022 - 2024 (\$000)
FORECAST PRICES AND COSTS

Year	Light & Medium Crude Oil First Attributed (MBbl) ⁽¹⁾	Light & Medium Crude Oil at Year-End (MBbl)	Heavy Crude Oil First Attributed (MBbl) ⁽¹⁾	Heavy Crude Oil at Year-End (MBbl)	Natural Gas First Attributed (MMcf) ⁽¹⁾	Natural Gas at Year-End (MMcf)	Natural Gas Liquids First Attributed (MBbl) ⁽¹⁾	Natural Gas Liquids at Year-End (MBbl)	Total First Attributed (MBoe) ⁽¹⁾	Total at Year-End (MBoe)
2022	4,451	28,649	23,938	26,432	17,874	91,849	1,103	6,034	32,471	76,423
2023	2,852	27,663	7,513	28,189	10,207	65,278	570	3,345	12,636	70,077
2024	2,547	23,378	7,436	30,958	13,417	64,850	711	3,810	12,930	68,954

(1) Refers to reserves first attributed in this fiscal year ending on the effective date.

Probable Undeveloped Reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are forecasted to be on stream within a five year timeframe. However, if the economic climate is not conducive to developing these reserves during such timeframe, Tamarack may, in its discretion, defer the development. There are a number of factors that could result in delays or cancelled development plans. These factors would include, but are not limited to, changing economic and technical conditions, surface access issues, the availability of services and access to pipeline or processing facilities. McDaniel and GLJ have forecasted the Company to spend approximately 47% of TPP FDC in 2025 and 2026. In 2027, 23% of the Company’s TPP FDC is expected to be invested, with approximately 29% remaining to be invested in the following two years. Tamarack expects that 99% of the TPP FDC forecast by McDaniel and GLJ will be invested within five years. The Company believes this allocation of capital investment and associated development of reserves is reasonable and is consistent with historical practices.

Significant Factors or Uncertainties Affecting Reserves Data

Although every reasonable effort is made to ensure that reserves estimates are accurate, reserves estimation is an inferential science. The process of estimating reserves requires significant estimates, assumptions and judgments based on current production forecasts, available geological, geophysical, engineering, and economic data available. These estimates can be significantly affected by fluctuations in commodity pricing, capital availability, operating costs, royalty regimes, government regulations and well performance. The estimates are revised as new information from ongoing development activities and production becomes available or as economic conditions impacting oil and gas prices and costs evolve.

Existing and future asset retirement obligation cost estimates for all active entities have been included in reserve report cash flow forecasts. Tamarack’s asset retirement obligations related to inactive areas with no reserves assigned are excluded from the reserve reports. Such approach is acceptable disclosure within NI 51-101 but does not meet the minimum recommendations within the COGE Handbook. Refer to Tamarack’s Annual Consolidated Financial Statements for the years ended December 31, 2024 and 2023 for the consolidated value of the Company’s total asset retirement obligations.

FUTURE DEVELOPMENT COSTS (\$000)
FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2024⁽¹⁾

Year	Total Proved Reserves (\$000)	Total Proved Plus Probable Reserves (\$000)
2025	358,519	404,667
2026	382,885	446,863
2027	315,581	426,067
2028	169,633	377,043
2029	44,641	155,940
2030	162	162
2031 & beyond	2,021	2,021
Total	1,273,443	1,812,763
10% Discounted	1,079,594	1,488,344

(1) Future development costs are associated with booked reserves in the McDaniel and GLJ Reports and do not necessarily represent the Company’s full budget.

Tamarack typically utilizes three sources of funding to finance its capital expenditure program consisting of internally generated adjusted funds flow, debt financing and equity issuances. The Company expects to fully fund its 2025 capital program with internally generated adjusted funds flow and available credit. Management does not currently anticipate the costs of funding to materially affect Tamarack's future net revenues from reserves nor result in uneconomic property developments.

RESERVES HELD FOR SALE AS AT DECEMBER 31, 2024
SOUTHERN ALBERTA LIGHT OIL ASSETS

Reserves attributes	Total
Proved (Mboe)	3,649
Probable (Mboe)	1,716
Proved plus Probable (Mboe)	5,365
Net Present Value of Future Net Revenue (Discounted at 10%)	\$ 80,918
Production (boe/d)	900
Netback (\$/boe)	\$ 30.49

On December 17, 2024, Tamarack entered into a purchase and sale agreement for the disposition of certain non-core oil and natural gas assets in Southern Alberta for \$28.0 million before closing adjustments. The transaction is contingent upon the receipt of third-party regulatory approval and is expected to close in the second quarter of 2025. As at December 31, 2024, the above reserves are considered as held for sale.

FINDING, DEVELOPMENT AND ACQUISITION COSTS (FD&A) PER BOE
FOR THE YEAR ENDED DECEMBER 31, 2024

(\$/Boe)	2024	2023	2022	3-Year Average
Proved Reserves				
Finding, development and acquisition cost	14.48	36.99	51.94	36.74
Finding and development costs	14.16	20.90	31.59	20.42
Acquisition costs	8.71	9.55	63.95	410.39
Proved plus Probable Reserves				
Finding, development and acquisition cost	10.45	103.55	35.55	31.48
Finding and development costs	10.94	20.86	37.05	19.60
Acquisition costs	15.04	7.55	35.12	115.03

FD&A costs are calculated by dividing total capital by reserve additions during the period. Total capital includes capital expenditures and changes in future development capital required to bring PUD reserves and Probable undeveloped reserves to production. Reserve additions is calculated as the change in reserves from the beginning of the applicable period excluding production.

While NI 51-101 requires that the effects of acquisitions and dispositions be excluded from the calculation of F&D costs, FD&A costs have been presented as acquisitions and dispositions can have a significant impact on the Company's reserve replacement costs. Excluding these amounts could result in an inaccurate portrayal of the Company's cost structure. F&D costs both including and excluding acquisitions and dispositions have been presented above. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development capital expenditures generally will not reflect total F&D costs related to reserves additions for that year. F&D costs are not necessarily calculated in the same manner by all issuers and should not be used to make comparisons amongst different issuers. See "Conventions".

Summary of Oil and Natural Gas Properties

Tamarack's oil and natural gas properties are all onshore and located in the province of Alberta, largely targeting the Clearwater, Charlie Lake and other enhanced recovery plays across Alberta. Tamarack's Clearwater assets cover the Northern (Nipisi and Seal), Central (Marten Hills and Canal) and Southern (Westlock and Jarvie) Clearwater plays. The Clearwater assets play a key role in driving Tamarack's free funds flow growth and contributing to its portfolio of long-life oil production. The Company is also pursuing enhanced oil recovery initiatives to lower decline rates, stacked zone development with multi-leg laterals to drive capital-efficient development programs and construction of an extensive pipeline and infrastructure network to enhance egress and market access. Through strategic acquisitions and a successful development program, Tamarack has established itself as the largest publicly traded Clearwater producer in Alberta.

Tamarack's Charlie Lake assets are in the northwestern region of Alberta (Wembley, Valhalla and Pipestone). The economics of the Charlie Lake light oil assets are driven by highly productive wells that enable quick payouts and strong rates of return. The formation is further enhanced by stacked zone potential with extended reach laterals, which support a cost-efficient development.

Additionally, Tamarack's ownership and operation of infrastructure and the availability of third-party handling and egress systems ensure the reliable and efficient development of the Charlie Lake assets.

Tamarack's enhanced oil recovery portfolio includes a diverse set of assets across Southern Alberta representing a wide range of formations and production types. Tamarack's key assets with production currently under waterflood include the Veteran Viking (Light Oil) and Eyehill Sparky (Medium Oil) oil plays. The strategic value of the enhanced oil recovery assets in Tamarack's portfolio is driven by the low decline and high estimated ultimate reserve recoveries. While these projects require significant water utilization, Tamarack has focused on innovating in waterflooded areas to minimize freshwater consumption, including recycling of produced water, utilization of non-fresh water source wells for injection and employing joint infrastructure to supply non-fresh water to area completion operations.

**OIL AND NATURAL GAS WELL COUNTS
AS AT DECEMBER 31, 2024**

Area	Crude Oil Producing (Gross)	Crude Oil Producing (Net)	Crude Oil Non-prod (Gross)	Crude Oil Non-prod (Net)	Natural Gas Producing (Gross)	Natural Gas Producing (Net)	Natural Gas Non-prod (Gross)	Natural Gas Non-prod (Net)
Clearwater	673	656.3	57	57	12	12	78	77.5
Charlie Lake	126	118.8	54	47.6	11	6.5	60	41.8
EOR & Other	544	510.9	328	300.4	397	301.3	268	212.9
Total	1,343	1,286	439	405	420	320	406	332

The non-producing oil wells and natural gas wells capable of production but which are not currently producing will be re-evaluated with respect to future product prices, proximity to facility infrastructure, design of future exploration and development programs and access to capital. Clearwater drilling involves multi-leg horizontal wells. One individual wellbore location may have up to eight lateral legs (events). For the purposes of this table, wells are counted by individual wellbore (not by multi-leg section or event). As at December 31, 2024, there were 281 net wells held for sale, including 87 net producing crude oil wells.

**DEVELOPED AND UNDEVELOPED ACREAGE COUNTS
AS AT DECEMBER 31, 2024**

	Undeveloped Acres (Gross)	Undeveloped Acres (Net)	Developed Acres (Gross)	Developed Acres (Net)	Total Acres (Gross)	Total Acres (Net)
Total	651,373	589,698	545,104	486,732	1,196,477	1,076,430

Greater than 98% of Tamarack's acreages were located in Alberta with remaining acreages held in Saskatchewan. Tamarack had leases on 37,128 net acres that expire in 2025. The Company expects to extend 31,086 net acres through ongoing drilling activities or leaseholder extensions. The remaining 6,042 net acres that are expected to expire in 2025 are not material to Tamarack's development plans. The Company reviews the economic viability of these undeveloped properties on the basis of pricing and capital availability and allocation. There is no guarantee that commercial reserves will be developed on these properties.

In calculating gross and net acreage in the table above, Tamarack counts an acreage twice if the Company holds interests in separate prospective formations under the same surface area under separate leases. The Company counts an acreage once if the Tamarack holds interests in separate prospective formations under the same surface area under a single lease. These lease counts are not material to the Company's land position.

Forward Contracts

Tamarack is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Tamarack may use certain derivative financial instruments and foreign exchange contracts to reduce a portion of the Company's corporate its exposure to fluctuations in commodity prices, increase the certainty of adjusted funds flow and to protect acquisition and development drilling economics. Such financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. Tamarack's Board of Directors reviews the Company's derivative and foreign exchange contract positions quarterly to ensure compliance with the pre-established risk management policies. A complete listing of the Company's derivative financial instruments can be found in the Annual Financial Statements for the years ended December 31, 2024 and 2023.

**PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT COSTS INCURRED
FOR THE YEAR ENDED DECEMBER 31, 2024**

Expenditures	Consists of	Amount (\$000)
Property acquisition costs – Unproved properties	<i>Acquisition costs and non-producing lease rentals</i>	1,297
Property acquisition costs – Proved properties	<i>Acquisition costs</i>	-
Property disposition costs – Proved properties	<i>Proceeds from disposition</i>	1,748
Exploration costs	<i>Geological, geophysical and exploration drilling</i>	14,963
Development costs ⁽¹⁾	<i>Drilling, completion, equipping, tie-in & facilities</i>	432,976
Other		1,669
Total		452,653

(1) Includes \$11.6 million of capital investments related to the Clearwater Infrastructure Partnership.

**NUMBER OF WELLS DRILLED
FOR THE YEAR ENDED DECEMBER 31, 2024**

Type of Well	Development Wells (Gross)	Development Wells (Net)
Light and Medium Oil	16	14.4
Heavy Oil	114	101.5
Natural Gas	-	-
Service	19	19.0
Dry and Abandoned	-	-
Stratigraphic Test	3	3.0
Total	152	137.9

**2025 DAILY PRODUCTION FORECAST IN THE RESERVE REPORT
AS AT DECEMBER 31, 2024**

		Gross Light & Medium Crude Oil (bbl/d)	Gross Heavy Crude Oil (bbl/d)	Gross Natural Gas (Mcf/d)	Gross Natural Gas Liquids (bbl/d)	Gross Barrel of Oil Equivalent (boe/d)
Total	Clearwater Oil Area	329	38,957	15,449	215	42,076
Proved	Charlie Lake Area	7,628	-	29,298	1,998	14,509
	EOR & Other	4,287	-	2,863	57	4,821
Total		12,244	38,957	47,610	2,270	61,407
Total	Clearwater Oil Area	333	43,530	17,360	240	46,997
Proved plus	Charlie Lake Area	9,924	-	35,793	2,464	18,354
Probable	EOR & Other	4,622	-	3,085	62	5,198
Total		14,879	43,530	56,238	2,767	70,549

**DAILY PRODUCTION HISTORY BY CORE ASSET AREA
FOR THE YEAR ENDED DECEMBER 31, 2024**

Property	Light & Medium Crude Oil (Bbl/d)	Heavy Crude Oil (Bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbl/d)	Total (Boe/d)
Clearwater Oil Area	293	38,069	17,718	258	41,574
Charlie Lake Oil Area	9,242	-	33,046	2,213	16,963
EOR & Other	4,611	-	5,730	82	5,648
Divested Properties	125	13	35	3	146
Total	14,271	38,082	56,529	2,556	64,331

PRODUCTION HISTORY
FOR THE YEAR ENDED DECEMBER 31, 2024

	3 Months Ended Mar 31/24	3 Months Ended Jun 31/24	3 Months Ended Sep 31/24	3 Months Ended Dec 31/24	12 Months Ended Dec 31/24
Average Daily Production					
Light and Medium Oil (Bbl/d)	15,270	14,807	13,203	13,822	14,271
Heavy Oil (Bbl/d)	36,255	37,660	39,047	39,341	38,082
Natural Gas (Mcf/d)	51,431	54,856	59,154	60,602	56,529
NGL (Bbl/d)	1,925	2,533	2,915	2,841	2,556
Total (Boe/d)	62,022	64,143	65,024	66,104	64,331
Average Net Production Prices Received					
Light and Medium Oil (\$/Bbl)	86.52	106.24	97.79	94.30	96.12
Heavy Oil (\$/Bbl)	76.36	88.23	84.98	79.69	82.37
Natural Gas (\$/Mcf)	2.93	1.51	0.87	1.71	1.72
NGL (\$/Bbl)	42.54	36.58	39.58	32.84	37.51
Total (\$/Boe)	69.69	79.06	73.46	70.12	73.08
Royalties Paid					
Light and Medium Oil (\$/Bbl)	22.74	25.39	39.32	12.99	24.91
Heavy Oil (\$/Bbl)	13.34	14.70	13.29	18.44	14.99
Natural Gas (\$/Mcf)	(0.33)	(0.19)	(0.77)	(0.78)	(0.54)
NGL (\$/Bbl)	10.88	8.85	10.73	10.16	10.13
Total (\$/Boe)	13.46	14.67	15.74	13.42	14.33
Net Production Expenses (including carbon tax)					
Light and Medium Oil (\$/Bbl)	15.72	18.12	14.89	13.99	15.72
Heavy Oil (\$/Bbl)	6.88	12.08	6.76	5.02	7.64
Natural Gas (\$/Mcf)	2.05	(2.49)	1.10	0.75	0.35
NGL (\$/Bbl)	-	-	-	-	-
Total (\$/Boe)	10.06	9.84	8.70	7.16	8.91
Transportation Costs					
Light and Medium Oil (\$/Bbl)	3.79	3.19	1.75	3.50	3.08
Heavy Oil (\$/Bbl)	4.56	4.51	2.67	3.35	3.74
Natural Gas (\$/Mcf)	0.55	0.49	0.35	0.47	0.46
NGL (\$/Bbl)	-	-	-	-	-
Total (\$/Boe)	4.18	3.93	2.36	3.30	3.43
Operating Field Netback Received					
Light and Medium Oil (\$/Bbl)	44.27	59.55	41.83	63.81	52.42
Heavy Oil (\$/Bbl)	51.57	56.94	62.26	52.88	56.00
Natural Gas (\$/Mcf)	0.66	3.70	0.20	1.27	1.44
NGL (\$/Bbl)	31.66	27.73	28.85	22.68	27.38
Total (\$/Boe)	42.00	50.61	46.66	46.24	46.41

Production volumes are presented on gross basis before the deduction of royalties. Production costs are composed of direct costs incurred to operate both oil and gas wells. Estimates are required to allocate these costs between product types. Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs. Production and transportation costs attributable to NGL have been included in the light and medium oil and natural gas amounts.

DESCRIPTION OF SHARE CAPITAL

Tamarack is authorized to issue an unlimited number of Common Shares and an unlimited number of Preferred Shares, issuable in series. As at December 31, 2024 there were 522,206,935 Common Shares issued and outstanding.

Common Shares

The holders of Common Shares are entitled to: (i) one vote for each Common Share held at all meetings of shareholders of the Company, except meetings at which only holders of a specified class of shares are entitled to vote; (ii) subject to the prior rights

and privileges attaching to any other class of shares of the Company, the right to receive any dividend declared by the Company; and (iii) subject to the prior rights and privileges attaching to any other class of shares of the Company, the right to receive the remaining property and assets of the Company upon dissolution.

Preferred Shares, Issuable in Series

The Company is authorized to issue an unlimited number of Preferred Shares, issuable in series. The Preferred Shares may be issued in one or more series at any time as determined by resolution of the Board of Directors. Subject to the provisions of the ABCA, the Board of Directors may fix the designation, rights, privileges, restrictions and conditions attaching to each series of the Preferred Shares prior to issuance by way of resolution.

Corporate Credit Ratings

S&P Global Ratings ("S&P")

Issuer Credit Rating	B
Senior Unsecured Notes	B+

The Company has both an issuer credit rating and a senior-unsecured note rating issue by S&P. These credit ratings were reaffirmed on November 21, 2024. S&P's credit rating scale ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Credit ratings affect the Company's ability to obtain short-term and long-term debt and equity financing and the cost of such financings. A reduction in the current credit ratings by the rating agencies, particularly a downgrade below the current ratings or a negative change in the ratings outlook, could adversely affect Tamarack's cost of financing and access to capital. In addition, changes in credit ratings may affect the Company's ability to: (i) enter into ordinary course derivative or hedging transactions and may require the posting of additional collateral under contracts; and (ii) enter into and maintain ordinary course contracts with customers and suppliers on acceptable terms.

There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant. Tamarack compensates S&P in connection with the assignment of ratings and publications.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares are listed and posted for trading on the TSX under the trading symbol "TVE". The following table sets forth the market price ranges and the trading volumes of the Common Shares for the financial year ended December 31, 2024 and as at February 14, 2024:

Month	Low (\$)	High (\$)	Volume
January 2024	\$ 2.92	\$ 3.29	42,192,500
February 2024	2.90	3.45	41,728,700
March 2024	3.40	3.85	55,461,500
April 2024	3.71	4.20	48,355,800
May 2024	3.48	3.88	43,680,300
June 2024	3.44	3.86	38,029,500
July 2024	3.64	4.13	46,884,600
August 2024	3.55	4.17	46,952,600
September 2024	3.49	4.30	58,096,900
October 2024	3.81	4.28	82,854,900
November 2024	4.16	4.62	61,715,100
December 2024	4.18	4.80	46,767,400
January 2025	4.40	5.05	46,817,100
February 2025	4.19	4.61	14,386,598

PRSU Grants

During the year ended December 31, 2024, the Company granted an aggregate of 2.9 million restricted share units ("RSUs") and 1.6 million performance share units ("PSUs") under its equity-settled Performance and Restricted Share Unit Plan ("PRSU Plan"). RSUs and PSUs will be settled in Common Shares of Tamarack by either or both of the following methods: (a) settlement in Common Shares acquired by the Company on the TSX; or (b) the issuance of Common Shares from treasury. For clarity, this does not include

restricted share awards or performance share awards granted under the Company's Cash Award Incentive Plan, which are anticipated to be settled in cash.

DIVIDENDS AND SHARE BUYBACKS

Dividends

During the year ended December 31, 2024, the Company paid \$81.5 million related to its monthly cash dividends on its Common Shares. The following table summarizes the dividends declared and distributed:

Declaration Date	Dividend (\$/share)
Tuesday, January 16, 2024	\$ 0.01250
Thursday, February 15, 2024	0.01250
Friday, March 15, 2024	0.01250
Monday, April 15, 2024	0.01250
Wednesday, May 15, 2024	0.01250
Friday, June 14, 2024	0.01250
Monday, July 15, 2024	0.01250
Thursday, August 15, 2024	0.01250
Tuesday, September 17, 2024	0.01250
Tuesday, October 15, 2024	0.01250
Friday, November 15, 2024	0.01275
Monday, December 16, 2024	0.01275
Tuesday, January 14, 2025	0.01275
Friday, February 14, 2025	\$ 0.01275

Tamarack intends to pay monthly cash dividends utilizing a portion of free funds flow earned by the Company (adjusted funds flow less capital investments and asset retirement obligations expenditures) to shareholders of record as of the dividend record date which is usually approximately 15 days prior to the dividend payment date. Tamarack's dividend policy is intended to provide shareholders with relatively stable and predictable monthly dividends, while retaining a portion of free cash flow to provide the Company with the financial flexibility to reduce net debt, buyback shares, pay dividends, modify the development plan or pursue strategic acquisitions, as deemed appropriate.

Share buybacks

In January 2024, the TSX approved the Company's application to renew its normal course issuer bid ("NCIB" or "share buybacks"). The NCIB allowed Tamarack to purchase up to 54.6 million Common Shares of the Company (representing approximately 10% of the 546.5 million issued and outstanding Common Shares that comprise the public float as of January 8, 2024) over a period of twelve months commencing on January 19, 2024. For the year ended December 31, 2024, the Company purchased and cancelled 33.9 million common shares at an average price of \$3.91 per common share, for a total repurchase cost of \$135.4 million, including \$2.6 million of federal taxes. All common shares purchased by Tamarack under the NCIB were cancelled. There were no common shares purchased for cancellation in 2023 under the previously approved NCIB.

In January 2025, the TSX approved the Company's application to renew its NCIB. The Company had 523.1 million Common Shares issued and outstanding as at January 6, 2025. The NCIB allows Tamarack to purchase up to 51.3 million Common Shares of the Company (representing approximately 10% of the 512.8 million issued and outstanding Common Shares that comprise the public float as of January 6, 2025) over a period of twelve months commencing on January 19, 2025. The NCIB will expire no later than January 18, 2026. The actual number of Common Shares which may be purchased pursuant to the NCIB will be determined by the Company. Any Common Shares that are purchased by Tamarack under the NCIB will be cancelled.

Under the NCIB, Common Shares are repurchased in open market transactions on the TSX or alternative Canadian trading system in accordance with the rules of the TSX governing NCIBs. The price paid by the Company for any such common shares is the prevailing market price at the time of purchase. In 2025, the total number of Common Shares the Company is permitted to reacquire is subject to a daily purchase limit of 663,380 Common Shares, representing 25% of the average daily trading volume of 2,653,522 Common Shares on the TSX calculated for the six-month period ended December 31, 2024. Notwithstanding the daily purchase limit, Tamarack may make one block purchase per calendar week which exceeds the daily repurchase restrictions.

The NCIB will continue to provide an additional tool for the reinvestment of excess free funds flow to increase long-term total shareholder returns. Tamarack believes that at times, the prevailing share price does not reflect the underlying value of the

common shares and the repurchase of common shares represents an opportunity to enhance per share metrics. Tamarack remains focused on balancing debt repayment and delivering enhanced returns to shareholders.

Capital Management

In determining the level of dividends or share buybacks to be distributed, the Board takes into consideration such factors as current and expected future levels of free funds flow, capital expenditures, borrowings and debt repayments, changes in working capital requirements and other factors. Over the long term, Tamarack expects to continue to pay dividends or buyback shares from its free funds flow; however, credit facilities may be used to stabilize such distributions from time to time. Growth capital expenditures will be funded from retained cash flow from operating activities, proceeds from asset dispositions and proceeds from additional debt or equity, as required. Although Tamarack intends to continue to make regular monthly dividends to shareholders, dividends or share buybacks are not guaranteed.



Notwithstanding the foregoing, the amount of future cash dividends declared and paid by Tamarack or share buybacks, if any, will be subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, compliance with any restrictions on the declaration and payment of dividends or share buybacks contained in any agreements to which Tamarack is a party from time to time (including, without limitation, the agreements governing Tamarack’s credit facilities or the senior unsecured notes), and the satisfaction of liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends.

The Board intends to review this policy on a periodic basis. Depending on the foregoing factors and any other factors that the Board deems relevant from time to time, many of which are beyond the control of the Board and Tamarack's management team, the Board may change this policy following any such review or at any other time that the Board deems appropriate. Any such change may result in future cash dividends or share buybacks being reduced or suspended entirely.

The Board intends dividends declared and paid by Tamarack will qualify as "eligible dividends" for the purposes of the Income Tax Act (Canada) (and any similar applicable provincial legislation), and thus qualify for the enhanced tax regime available to certain shareholders. The Board therefore intends to designate dividends paid by Tamarack as "eligible dividends" and notify shareholders that dividends are "eligible dividends" for these purposes by posting a general notice to this effect on Tamarack's website and by disclosing this fact in each press release that Tamarack issues that contains a dividend announcement. Notwithstanding the foregoing, no assurances can be given that all dividends will qualify as "eligible dividends" and the designation of dividends as "eligible dividends" will be subject to the discretion of the Board.

DIRECTORS AND EXECUTIVE OFFICERS

The following table lists the names of the directors and officers, their municipalities of residence, positions and offices with the Company and principal occupations. All directors have been elected to serve as such until the Company’s next annual meeting of shareholders, or until his or her successor is duly elected, unless his or her office is vacated earlier in accordance with the by-laws of the Company or applicable law.

<p>John Rooney⁽¹⁾⁽³⁾⁽⁴⁾</p>	<p>Chairman of the Board</p>
	<p>Mr. Rooney is a Calgary-based entrepreneurial executive with a technical background in finance and is Chair of Kara Technologies Inc., an organization dedicated to the development of next generation technology for the economic production of low emissions fuels. Mr. Rooney is also on the Board of Western Energy Services. Prior thereto, Mr. Rooney founded and ran a number of public oil and gas companies, holding various executive roles. In addition to his strong working knowledge of the oil and gas industry, Mr. Rooney brings exceptional value to the Tamarack Board of Directors through his more than 20 years of public, private and not-for-profit directorships. He also brings a unique stakeholder and sustainability perspective from his five years as director with Export Development Canada and his current role with Kara Technologies. Mr. Rooney is a Chartered Professional Accountant and a Chartered Business Valuator.</p> <p>Calgary, Alberta Director Since: March 2021</p>
<p>Caralyn Bennett⁽²⁾⁽⁴⁾</p>	<p>Independent Director</p>
	<p>Ms. Bennett is a professional engineer and is currently the President of the Canadian Heavy Oil Association and serves as a director Acceleware Ltd. and a private oil and gas producer based in Western Canada. Prior thereto she held the role of Executive Vice President and Chief Strategy Officer of GLJ Ltd. and various senior technical roles at GLJ and at upstream oil and gas companies.</p> <p>Calgary, Alberta Director Since: March 2023</p>

John Leach⁽¹⁾⁽²⁾

Independent Director



Mr. Leach is a Chartered Professional Accountant with over 35 years of oil and gas experience. He was previously the Executive Vice President & Chief Financial Officer of Crew Energy Inc., a role he has held since Crew's inception in 2003 until its successful sale in 2024. Prior to Crew, Mr. Leach was a founding member of Baytex Energy Ltd. in 1993, serving in its finance department in increasing roles of responsibility culminating as its Vice President, Finance. Mr. Leach holds a Bachelor of Commerce degree from the University of Saskatchewan.

Calgary, Alberta
Director Since: January 2017

Marnie Smith⁽¹⁾⁽³⁾

Independent Director



Ms. Smith is a Managing Director at Russell Reynolds Associates, a global organizational consulting firm, where she leads the Western Canadian team and Canadian energy platform and is part of the firm's global Board and CEO Advisory Practice. Prior thereto, she served as a Senior Client Partner with Korn Ferry and as Managing Director & Head of Canadian Energy at Macquarie Group.

Calgary, Alberta
Director Since: April 2020

Rene Amirault⁽⁴⁾

Independent Director



Mr. Amirault is an accomplished and experienced energy executive. He was previously the CEO of SECURE Energy Services Inc. ("SECURE"). He has also held the roles of President and Chairman of the Board of SECURE. Mr. Amirault is currently on the Board of Directors of SECURE as Vice Chair. He has held various roles at Canadian Crude Separators Inc. and CCS Income Trust, including Vice President roles in Sales and Marketing, Business Development and Corporate Development. Mr. Amirault holds a Certified General Accountant designation.

Calgary, Alberta
Director Since: June 2024

Robert Spitzer⁽²⁾⁽³⁾

Independent Director



Mr. Spitzer is an experienced professional in the upstream oil and gas field. Mr. Spitzer is currently an independent businessman. He was previously the Executive Vice President of Apache Kitimat Upstream from 2013 to 2015 and the Vice President New Ventures of Apache Canada Ltd. from 2005 to 2012. Prior thereto, Mr. Spitzer held a variety of exploration and development focused positions with US based and international oil and gas companies.

Bragg Creek, Alberta
Director Since: June 2017

Shannon Joseph⁽⁴⁾

Independent Director



Ms. Joseph is a professional engineer and is currently serving as Chair of Energy for a Secure Future. Previously, Ms. Joseph served as Vice-President, Government Relations and Indigenous Affairs with the Canadian Association of Petroleum Producers (CAPP) and as the founding Director of the Municipalities for Climate Innovation Program with the Federation of Canadian Municipalities. Over her career, she has served in senior roles focused on federal environmental policy, Indigenous and stakeholder relations and environmental program implementation.

Calgary, Alberta
Director Since: February 2024

Brian Schmidt

Director, President & Chief Executive Officer



President and Chief Executive Officer of the Company and Founder of its privately-held predecessor since 2009, Mr. Schmidt is also an Honorary Chief of the Blood Tribe. He is currently a director on the Board of Governors of the Canadian Association of Petroleum Producers and is an advisor to the Indian Oil & Gas Co-Management Board, assisting First Nations with policy development. He is also on the board of The Explorers and Producers Association of Canada.

Calgary, Alberta
Director Since: June 2010

Steve Buytels

Chief Financial Officer



Mr. Buytels is a CFA® charterholder and has held the role of CFO with the Company since he joined in 2020. Prior to joining Tamarack, he held Managing Director, Principal or similar roles in equity and debt capital markets with independent investment dealers. Mr. Buytels brings diverse oil and gas capital markets, finance and advisory experience.

Calgary, Alberta

Kevin Screen

Chief Operating Officer



Mr. Screen is a professional engineer and has been COO of the Company since July 2021. Prior thereto, he held the role of VP, Production and Operations since September 2011. Before joining Tamarack, he held leadership and technical positions with the Canadian arm of a U.S. based producer since 2002.

Calgary, Alberta

Ben Stoodley

Vice President Engineering



Mr. Stoodley is a professional engineer and has served as Vice President Engineering since 2022 and has been with the organization in technical roles since 2021. Prior thereto, he held the role of Manager, Development at West Lake Energy from 2017 to 2021. Mr. Stoodley brings significant experience in production engineering, business development and field development roles, as well as conventional heavy oil experience.

Calgary, Alberta

Christine Ezinga

Vice President Business Development & Sustainability



Ms. Ezinga is a CFA® charterholder and joined the Company in 2021. Prior thereto, she held the role of VP of Strategy and Planning with Black Swan Energy. Ms. Ezinga brings diverse experience in capital markets, finance, investor relations and business development from prior roles at several Canadian oil and gas producers.

Calgary, Alberta

Kevin Johnston

Vice President Finance



Mr. Johnston is a Chartered Professional Accountant and has served as Vice President Finance since August 2023. Prior thereto, he held the role of Vice President, Finance & Controller at a division of Canadian Utilities Limited, a diversified global corporation. Mr. Johnston brings 20 years of finance experience with various Canadian energy and professional services companies, including leading organization-wide finance strategy creation and execution.

Calgary, Alberta

Lynne Chrumka

Vice President Exploration



Ms. Chrumka is a professional geologist and joined the Company in 2022 in her current role. Prior thereto, she held the role of VP Geosciences at ARC Resources and Seven Generations Energy. Ms. Chrumka brings significant experience in domestic and global exploration in addition to significant technical and leadership experience.

Calgary, Alberta

Rocky Baker

Vice President Marketing



Ms. Baker brings over 18 years of oil and gas marketing experience. She most recently served as Manager of the Commercial Services Group at Inter Pipeline. Prior to, Rocky worked 11 years in Cenovus' marketing department in both the Upstream and Downstream divisions. She specialized in expansions and new projects due to her ability to successfully plan and execute changes. Rocky holds a Chartered Professional Accounting (CPA) Designation and a Bachelor of Commerce from the University of Calgary.

Calgary, Alberta

Scott Shimek

Vice President Production & Operations



Mr. Shimek is a professional engineer and has been with Tamarack since 2021. Prior thereto, he held the role of Vice President, Resource Development with Bonavista Energy. Mr. Shimek brings significant experience in the energy industry, having integrated his diverse technical knowledge into various leadership roles.

Calgary, Alberta

Sony Gill

Corporate Secretary



Mr. Gill is a partner in the Capital Markets and Mergers & Acquisitions Groups at the Stikeman Elliott LLP law firm, with a practice focusing on public and private company creation, growth, restructuring and value maximization. Prior to joining Stikeman Elliott, Mr. Gill was a partner at another major Canadian law firm.

Calgary, Alberta

- (1) Director is a member of the Board of Directors' audit committee.
- (2) Director is a member of the Board of Directors' reserves committee.
- (3) Director is a member of the Board of Directors' corporate governance and compensation committee.
- (4) Director is a member of the Board of Directors' environment, safety and sustainability committee.

As of February 14, 2025, the directors and executive officers of the Company as a group beneficially own, directly or indirectly, or exercise control or direction over, an aggregate of 8,795,409 Common Shares, representing approximately 1.62% of the Common Shares issued and outstanding on a non-diluted basis.

Cease Trade Orders

To the knowledge of management, no director or executive officer of the Company is, as at the date of this AIF, or has been, within 10 years before the date of this AIF, a director, chief executive officer or chief financial officer of any company (including the Company) that: (i) was subject to an order (as defined below) that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes of this part, "order" means: (i) a cease trade order; (ii) an order similar to a cease trade order; or (iii) an order that denied the relevant company access to any exemption under securities legislation, in each case, that was in effect for a period of more than 30 consecutive days.

Bankruptcies

Except as described below, to the knowledge of management, no director or executive officer of the Company, nor any shareholder holding a sufficient number of Common Shares to materially affect the control of the Company: (i) is, or has been within the 10 years before the date of this AIF, a director or executive officer of any company (including the Company) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (ii) has, within the 10 years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold such person's assets.

Penalties or Sanctions

To the knowledge of management, no director or executive officer of the Company, nor any shareholder holding a sufficient number of Common Shares to materially affect the control of the Company, has: (i) been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in deciding whether to make an investment decision.

Conflicts of Interest

The directors or officers of Tamarack may also be directors or officers of other oil and natural gas companies or otherwise involved in natural resource exploration and development and situations may arise where they are in a conflict of interest with Tamarack. Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with Tamarack to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

AUDIT COMMITTEE INFORMATION

The purpose of the Company's audit committee ("**Audit Committee**") is to provide assistance to the Board of Directors in fulfilling its legal and fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Company. It is the objective of the Audit Committee to maintain open communication among the Board of Directors, the independent auditors and senior management of the Company.

Audit Committee Mandate and composition

Tamarack's Audit Committee mandate sets out the committee's purpose, organization, duties and responsibilities. A copy of the mandate is attached hereto as Appendix "C". The Committee is comprised of John Leach, John Rooney and Marnie Smith, all of whom are financially literate, as such term is defined in NI 52-110, and all of whom are considered independent under NI 52-110.

Relevant Education and Experience

John Leach

Mr. Leach is a CPA, CA who served as Executive Vice President and Chief Financial Officer of Crew Energy Inc., a TSX listed, oil and natural gas producer from 2003 to 2024. Mr. Leach was formerly a founding member of Baytex Energy Ltd. in 1993, serving in the finance department in increasing roles of responsibility culminating as its Vice President, Finance from 1998 to 2003. Prior to Baytex, Mr. Leach worked for KPMG, LLP. Through all of his roles, Mr. Leach has acquired significant experience and exposure to accounting and financial reporting issues as well as capital markets procedures, policies and rules. Mr. Leach has been a Chartered Accountant since 1991, after graduating from the University of Saskatchewan with a Bachelor of Commerce degree.

John Rooney

Mr. Rooney is a Calgary-based entrepreneurial executive with a technical background in finance and is Chairman of Kara Technologies Inc., an organization dedicated to the development of technology for the economic production of low emissions fuels. Mr. Rooney is also on the Board of Western Energy Services. Prior thereto, he founded and ran a number of public oil and gas companies, holding various executive roles. Mr. Rooney brings exceptional value to the Tamarack Board of Directors through his more than 20 years of public, private and not-for-profit directorships. Mr. Rooney is a Chartered Accountant and a Chartered Business Valuator.

Marnie Smith

Ms. Smith is a Managing Director at Russell Reynolds Associates, a global organizational consulting firm, where she has led the Western Canadian team and Canadian energy platform and has been a member of the Global Industrial and Natural Resources and Financial Services practices since October 2021. Prior thereto, she served as Senior Client Partner with Korn Ferry from September 2017 and as Managing Director & Head of Canadian Energy at Macquarie Group, practicing in the upstream, midstream and energy

services sectors from 2004. Ms. Smith brings extensive experience working with North American and global energy companies' executives and boards through the delivery of strategic and M&A advice; financing solutions; corporate and asset valuation; and transaction evaluation, execution and negotiations. She holds a Bachelor of Commerce (Distinction) and a Bachelor of Arts, International Relations (Distinction) from the University of Calgary, as well as a Master of Finance from INSEAD.

Audit Committee Oversight

Since January 1, 2014, Tamarack's board of directors has adopted all recommendations of the Audit Committee to nominate or compensate an external auditor.

Reliance on Certain Exemptions

Since January 1, 2013, the Company has not relied on the exemptions contained in Section 2.4 or Part 8 of NI 52-110.

Pre-Approval Policies and Procedures

The Audit Committee has established a pre-approval policy and procedures for the engagement of non-audit services. The Audit Committee must approve all engagements for non-audit services which are expected to exceed \$50,000 per engagement before the engagement may commence. For engagements of non-audit services which are expected to be less than \$50,000, and which result in aggregate annual non-audit fees of less than \$50,000 at completion, the engagement may commence upon approval by the Chairman of the Audit Committee with all members being informed of the service at the next meeting of the Audit Committee. All recommendations for services will be submitted by the Vice-President, Finance and Chief Financial Officer.

External Auditor Service Fees

KPMG LLP has served as Tamarack's external auditors since Tamarack's formation in 2002. The following table summarizes the fees paid or payable to KPMG LLP (by calendar engagement year):

Year ended December 31	2024	2023
Audit fees	\$ 657,575	\$ 631,300
Audit-related fees	80,250	74,900
Tax fees	100,794	201,053
Total fees	\$ 838,619	\$ 907,253

Audit fees consist of the aggregate fees billed for the audit or review of the Company's annual and quarterly financial statements, services that are normally provided in connection with statutory and regulatory filings and the audit of the Clearwater Infrastructure Limited Partnership. Audit-related fees consist of the aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements and are not reported as audit fees.

INDUSTRY CONDITIONS

The North American oil and natural gas industry is subject to extensive regulation and taxation as a result of various legislation enacted by various levels of government, all of which should be carefully considered by investors in the Canadian petroleum and natural gas industry. All current legislation is a matter of public record and Tamarack is unable to predict what additional legislation may be enacted. While it is not expected these laws and regulations will affect the operations of the Company in a manner materially different than how they would affect other oil and gas corporations of a similar size, investors should consider these factors carefully. Outlined below are some of the principal aspects of the directives governing the oil and natural gas industry in Western Canada.

Pricing and Marketing in Canada

Crude Oil

In Canada, oil producers can negotiate volume and sales contracts directly with purchasers. The price is established the local and global market forces. Oil prices are primarily based on worldwide supply and demand, but regional market and transportation issues also influence prices. Specific prices that a producer receives will depend, in part, on oil quality, prices of competing fuels, distance to market, offtake capacity access to downstream transportation, value of refined products, length of contract term, weather conditions, the balance of supply and demand and other contractual terms. The trajectory of oil prices continues to be subject to uncertainty and volatility, factors such as transportation disruptions, impact of tariffs or threats of tariffs, extreme weather events, offtake capacity constraints, OPEC+ production policies, supply constraints and the conflict in Ukraine and the Middle East continue to be unpredictable and may have an ongoing impact on oil demand and prices. See "Risk Factors – Political Uncertainty".

Canadian and North American oil and gas production is forecasted to continue to grow, taking advantage of greater access to pipelines, signaling a ramp-up in growth and demand for crude oil production in the country. Recent rhetoric from the US Federal Government has also reflected a desire for less regulation and higher drilling and development activities which may spur higher field development activities. The anticipated growth in exports is supported by the commencement of the Trans Mountain Pipeline in 2024 which has increased the pipeline's capacity by 590,000 barrels per day, to a total of 890,000 barrels per day. Growth in North American supply could result in commodity price declines in the near term.

Natural Gas

In Canada, natural gas producers can negotiate volume and sales contracts directly with purchasers. The price is established the local and global

market forces. The price received by a natural gas producer depends on the price of competing natural gas supplies, the volume of NGLs prevalent in the gas stream (the “energy/heat content”), distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms of sale. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms. Despite expectations that export capacity will increase in Canada as a result of the anticipated commercial operation of LNG Canada to Asia markets in mid-2025, natural gas prices are expected to remain subdued in 2025 in light of the warmer 2024/25 winter and elevated supplies relative to lower local demand. High production levels in both Canada and the U.S., alongside elevated storage reserves in North America have collectively contributed to lower natural gas prices.

Natural Gas Liquids

The pricing of condensates and other NGL consisting of ethane, butane, propane and pentanes sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGL is based on the products being of greater economic value when sold separately instead of together within the natural gas stream, relative to the incremental operating costs associated with multi-phase liquid separation. Such prices depend on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance, access to liquids fractionation and other contractual terms.

Exports from Canada

The Canadian Energy Regulator’s (“CER”) governing legislation is the Canadian Energy Regulator Act (“CERA”) and the Amended IAA (as defined herein). The CER responsibilities include general oversight of Canadian oil and natural gas industry including the development of multi-jurisdictional development projects and the export of crude oil, natural gas and NGL from Canada. Exports of crude oil, natural gas and NGL from Canada are subject to CERA and remain subject to the National Energy Board Act Part VI (Oil and Gas) Regulation (the “Part VI Regulation”). The CERA and the Part VI Regulation authorize crude oil, natural gas and NGL exports under: (i) short-term orders for up to one or two years depending on the substance, and up to 20 years for quantities of natural gas (other than NGL) not exceeding 30,000 m3 per day; or (ii) long-term export licences of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g. NGL). In addition to CER approval, long-term export licences also requires various other ministerial and federal Cabinet approvals. Receipt of such approvals are subject to uncertainty.

Transportation Constraints, Pipeline Capacity and Market Access

A major constraint to the export of crude oil, natural gas and NGL is the deficit of transportation capacity to transport production from Western Canada to the U.S. and other international markets. Although numerous pipeline transportation projects have been announced or are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Due in part to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Pipelines

Producers negotiate with pipeline operators to transport their products to market on a firm, spot or interruptible basis depending on the specific pipeline and the specific substance. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers and the price received.

Under the Canadian Constitution, interprovincial and international pipelines fall within the federal government’s jurisdiction and, under the CERA, construction of interprovincial and international pipelines (new or expansion capacity) will require a federal regulatory review and Cabinet approval before they can proceed. Recent years have seen a perceived lack of policy and regulatory certainty such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments, public interest groups and legal opposition related to issues such as Indigenous rights and title, the government’s duty to consult and accommodate Indigenous peoples and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

Specific Pipeline Updates

In December 2023, Michigan Regulators approved Enbridge Inc’s (“Enbridge”) Line 5 Tunnel Replacement Project, marking the end of a more than three year long evaluation process. Line 5 is seen as crucial infrastructure supplying Michigan, Ontario and Quebec. This approval begins the process of replacing seven kilometres of the current pipeline with a new underwater tunnel in the Straights of Mackinac. The pipeline will be housed within a concrete tunnel beneath the lakebed. The tunnel project must first be approved by the U.S. Army Corps of Engineers at the United States federal level before construction can commence. The U.S. Army Corps of Engineers has initiated an environmental impact assessment, which is expected to be completed by 2026.

Construction of the Trans Mountain Pipeline expansion, which received Cabinet approval in November 2016, was completed in April 2024, and service began in May 2024. The original pipeline and the newly completed expansion now operate collectively. Since commercial operation of the project expansion began, data from June to September 2024 suggests that the pipeline expansion has been exporting at about 600,000 barrels per day, of which 40% was exported to the U.S. and the remaining 50% was distributed for exports abroad at the Westridge Marine in Burnaby, British Columbia.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the Oil Tanker Moratorium Act (the “OTMA”), which imposes a ban on tanker traffic transporting certain crude oil and NGL or persistent crude oil products in excess of 12,500 metric tonnes along British Columbia’s north coast. The ban may prevent pipelines from being built to, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium.

Natural Gas and LNG

Natural gas prices in Alberta and British Columbia have been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to infrastructure to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which is generally lower than the prices received in other North American markets as a result of

lower offtake demand and capacity.

Required repairs or upgrades to the primary pipeline systems in Western Canada have also led to further reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. In October 2020, TC Energy Corporation (“TC”) received federal approval to expand the Nova Gas Transmission Line System (the “NGTL System”). The NGTL System is in the midst of implementing a \$9.9 billion infrastructure program to add 3.58 billion cubic feet per day of capacity. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline. LNG Canada eventually plans to double the facility’s capacity with a proposed Phase 2 expansion. In addition, in June 2024 the proposed Cedar LNG project, a floating LNG facility also located in British Columbia, reached a successful final investment decision, and is expected to be in service in late 2028.

Development of both provincial and federal frameworks may also impose restrictions on natural gas and LNG projects in Canada, particularly as provincial and federal governments work to achieve emissions reduction targets. Such frameworks are expected to introduce more stringent restrictions on carbon emissions, with the potential for increased compliance costs, operational delays and restrictions on a new project approvals. See also “Industry Conditions – Federal Environmental Regulations”, “Industry Conditions – Alberta Environmental Regulations”, “Industry Conditions – Federal Climate Change Regulations” and “Industry Conditions – Alberta Climate Change Regulations”.

LNG Export Terminals

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, opposition from environmental and Indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. There are currently eight LNG export projects at various stages of development primarily located in British Columbia. LNG Canada’s LNG liquefaction facility and export terminal in Kitimat, British Columbia will be the first operational large-scale LNG export facility in Canada. The facility is expected to export up to 14 million tonnes of LNG per year. Producers will be able to transport natural gas to the facility via the recently completed Coastal GasLink pipeline. The export facility is over 95% complete and first shipments of LNG are anticipated in 2025.

Trade Agreements

Trade between the North American countries of Canada, the United States and Mexico is governed by the Canada United States Mexico Agreement. The agreement came into force on July 1, 2020. As the United States is Canada’s primary trading partner and the largest international market for the export of crude oil, natural gas and NGL from Canada, the implementation of these trade agreements impacts Western Canada’s petroleum and natural gas industry at large, including the Company’s business.

Most recently, the US Federal Government has announced the imposition of a 10% tariff on Canadian oil and natural gas exports, although this has been temporarily suspended. There remains uncertainty regarding whether these tariffs will be re-implemented. While Tamarack is unable to predict with certainty what the impact of such tariffs will have on the business, however, there could be a significant negative impact to the price Tamarack receives for its oil sales. As Canada-U.S. trade relations continues to develop, the potential for further tariff-related conflicts could introduce additional volatility and risks to Tamarack’s operations.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in Western Canada’s provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. The leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral rights owner to have access to the surface lands as well. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, however, each province has developed its own process that producers can follow to obtain and maintain the surface access necessary to conduct operations throughout the lifespan of a well, facility or pipeline.

The provincial government in Alberta owns most of the mineral rights to the oil and natural gas located within its provincial borders. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments in lieu thereof. Provincial governments in Western Canada conduct land sales where oil and natural gas companies bid for the leases necessary to explore for and produce oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

Private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop oil and natural gas reserves.

An additional category of mineral rights ownership includes ownership by the Canadian Federal Government of some legacy mineral lands and within Indigenous reservations designated under the Indian Act (Canada), which is managed and regulated by a separate government body according to distinct legislation.

Royalty Regime in Canada

Each province has legislation and regulations which govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. Provincial royalty regimes operate in conjunction with applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain provincial

taxes and other charges on production or revenues may be payable. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production. Producers and working interest owners of oil and natural gas rights may create additional royalties such as overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for volume-based incentive programs, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low. The incentive programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry, prioritize certain kinds of development or undertake initiatives using new technologies. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or to utilize technologies that enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance.

Regulatory Authorities and Environmental Regulation

The Canadian oil and gas industry is subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation related to air pollution and greenhouse gas (“GHG”) emissions (typically expressed in terms of carbon dioxide equivalent (“CO₂e”)), may impose further requirements on operators and other companies in the oil and gas industry. Companies that have hydraulic fracturing operations have additional operational regulatory and reporting requirements.

Federal Environmental Regulations

While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails. The federal government has primary jurisdiction over federally regulated industries such as railways, aviation and interprovincial transport. The CERA and the IAA provide the foundation for the federal government to protect the environment and is enforced by the Impact Assessment Agency (“IA Agency”).

The pre-amendment Impact Assessment Act (the “Pre-Amendment IAA”) relied on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment. The impact assessment requires consideration of the project’s potential adverse effects and the overall societal impact that a project may have on environmental, biophysical and socio-economic factors and impacts to Indigenous rights. It also requires an expanded public interest assessment, including Indigenous consultation. The impact assessment looks at the direct result of the project’s construction and operation. Designated projects specific to the petroleum and natural gas industry include pipelines that require more than 75 km of new right of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

On October 13, 2023, the Supreme Court of Canada concluded that the “designated projects” component of the IAA was partially unconstitutional due to its encroachment of provincial jurisdiction beyond federal authority. An interim guidance was enacted following the Supreme Court ruling. In June 2024, the federal government enacted amendments to the IAA through the *Budget Implementation Act, 2024, No. 1* (the “Amended IAA”). The Amended IAA largely preserved the assessment framework of the Pre-Amendment IAA but replaced the assessment of designated projects from a broader consideration of potential adverse effects and social impacts to a narrowed assessment of adverse effects, defined as non-negligible adverse changes, within the federal jurisdiction. In deciding whether an impact assessment is required, the Amended IAA added whether a means other than an impact assessment exists that would permit a jurisdiction to address the federal effects as another factor for the IA Agency’s consideration. Additionally, the final project approval decision is subject to a heightened test and must consider whether the effects are likely to be, to some extent, significant. The full implications of the amendments are yet to be interpreted in practice through the Amended IAA has not fully addressed criticism from project proponents that the applicability, timelines and decision-making powers under the Amended remain uncertain and unpredictable.

On July 1, 2023, the CFS Regulations came into force. The objective of the clean fuel standard is to achieve 30 million tonnes of annual reductions in GHG emissions by 2030. The CFS Regulations requires liquid fossil fuel primary suppliers to reduce the carbon intensity of the liquid fossil fuels they produce in, and import into, Canada. The CFS Regulations has also established a credit market, whereby the annual carbon intensity reduction requirement can be met via three main categories of credit-creating actions: (i) actions that reduce the carbon intensity of the fossil fuel throughout its lifecycle; (ii) supplying low-carbon fuels; and (iii) specified end-use fuel switching in transportation.

The Federal Government prescribes the Output-based Pricing System (the “OBPS”) regulations under the Greenhouse Gas Pollution Pricing Act (the “GGPPA”). The GGPPA and OBPS act as backstop legislation for taxing carbon emissions in provinces that have not implemented their own carbon tax legislation that meets Federal equivalency requirements. The GGPPA system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country. Effective January 1, 2025, the minimum price permissible under the GGPPA rose to \$95/tonne of CO₂e.

On December 7, 2023, the federal government published the Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap (“GHG Cap”) and on November 9, 2024, published the Proposed Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations (“Proposed GHG Cap Regulation”). Under the Proposed GHG Cap Regulation, crude oil production, oil sands extraction and upgrading as well as LNG projects would be captured by the cap-and-trade system. Key elements of the Proposed GHG Cap Regulation consist of: (i) a reporting system requiring

cumulative production report of all of the operator's facilities, as well as the GHG and production report, attributable to each facility, calculated in accordance with prescribed quantification methods and (ii) emission remittance obligations for all operators with production in excess of 365,000 barrels per year, where operators above the production threshold must remit one compliance unit for each tonne of carbon dioxide equivalent tonne of their emissions. Under the Proposed GHG Cap Regulation, remittance obligations may be satisfied by emission allowances prescribed by the minister, eligible Canadian offset credits or decarbonization units obtained from making contributions to a decarbonization program per carbon dioxide equivalent tonne. The Proposed GHG Cap Regulation is expected to come into force in 2025. The initial reporting responsibilities could come into effect as early as 2026, while the complete system requirements are set to be gradually implemented between 2026 and 2030.

In June 2023, the International Sustainability Standards Board ("ISSB") issued two international environmental reporting standards: IFRS S1, which addresses sustainability-related disclosure, and IFRS S2, which addresses climate-related disclosure. The Canadian Sustainability Standards Board ("CSSB") subsequently released for public comment substantially similar proposed Canadian versions of the international standards ("CSDS 1" and "CSDS 2"), which were finalized in December 2024 (collectively, the "Canadian Standards").

The Canadian Standards require issuers, among other things, to include quantitative data regarding their environmental considerations, to use scenario analysis in developing their disclosure, and to disclose Scope 3 emissions (i.e. indirect emissions from an organization's operations). The finalized Canadian Standards are substantially similar to IFRS S1 and S2 (and earlier drafts of CSDS 1 and CSDS 2), however they have extended implementation timelines for select criteria. Canadian companies are not required to follow the Canadian Standards at this time, however the Canadian Securities Administrators are considering amending Canadian reporting requirements to include certain aspects of these new Canadian Standards; to what extent they will be adopted remains unclear.

In June 2024, the federal Competition Act was amended to enact new deceptive marketing provisions targeting "greenwashing". The new provisions introduced unclear substantiation requirements for companies making environmental claims and significant fines for failing to meet the new requirements. As a result of the uncertainty with respect to the applicability of the new rules, some companies removed their environmental and sustainability-related disclosure from the public domain. In December 2024, the constitutionality of the new deceptive marketing provisions was challenged in the Alberta Court of King's Bench and the lawsuit remains ongoing.

Alberta Environmental Regulations

The discharge of crude oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties requiring Tamarack to incur costs to remedy such discharge if they are not covered by the Company's insurance. Although the Company maintains insurance to industry standards, there is uncertainty that such insurance will cover all possible environmental events. In addition, future changes to environmental legislation may impose further requirements on the oil and natural gas industry.

The Alberta Energy Regulator ("AER") is the principal regulator responsible for all energy development in Alberta. It derives its authority from the Responsible Energy Development Act (Alberta) and a number of related statutes including the Oil and Gas Conservation Act, the Oil Sands Conservation Act, the Pipeline Act, and the Environmental Protection and Enhancement Act. The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities. The Government of Alberta's land-use policy in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province.

The AER monitors seismic activity across Alberta to assess the risks associated with increased seismicity induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand and other additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate crude oil and natural gas production. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further. The AER has developed monitoring and reporting requirements that apply to all crude oil and natural gas producers working in certain areas where the likelihood of increased seismic activity is higher and implemented various Subsurface Orders. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of ongoing monitoring.

Alberta Liability Management Programs

Under Canadian common law, receivers and trustees cannot avoid a legislated authority's imposition of abandonment orders against licencees or to require a licencee to pay a security deposit before approving a transfer when such a licencee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. The legislation places the burden of a defunct licensee's abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the orphan fund (the "Orphan Fund") to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner.

Alberta established an Orphan Fund which is run by the Orphan Well Association ("OWA") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline if a licencee or working interest participant becomes insolvent or is unable to meet its obligations. The Government of Alberta has also loaned the Orphan Fund significant amounts of funds to sustain operations.

Alberta has committed to actively reducing inventories of orphan and inactive well sites in the province. The AER oversees liability management in the province through its new Liability Management Framework (“LMF”), released as of February 7, 2025 pursuant to AER Bulletin 2025-04. The goal of the LMF is to prescribe a holistic and full lifecycle approach to reclamation and remediation obligations. The LMF assists the OWA by creating a framework and regulatory scheme to manage site reclamation throughout the lifecycle of a project. Developments under the LMF include a Licensee Capability Assessment System, an Inventory Reduction Program, and a Licensee Management Program. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licencees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

Under the LMF, each licencee is required to meet mandatory annual spend targets for well closures and abandonments. Certain licencees may also elect to provide the AER with a security deposit in place of their closure spend target. The LMF also provides proactive support to distressed operators and will require companies operating in Alberta's petroleum and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations in accordance with five-year rolling spending targets.

The Licensee Capability Assessment System provides a comprehensive assessment of corporate health and considers a wider variety of factors than those considered under the former Management Rating Programs by establishing clear expectations for industry with regards to the management of liabilities throughout the entire lifecycle of crude oil and natural gas projects. In addition to the Licensee Capability Assessment System, Directive 088 implemented other liability management programs for the AER to monitor licencees over the life-cycle of a project. High risk licencees under the program may be subject to various tools employed by the AER to ensure that liability obligations are fulfilled.

Federal Climate Change Regulations

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the regulation of the oil and natural gas industry in Canada. These impacts are uncertain and it is not possible to predict the extent of future requirements. Any new laws and regulations could have a material impact on the Company's operations and cash flow.

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the “UNFCCC”) since 1992. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. The Glasgow Climate Pact at the 2021 United Nations Climate Change Conference reaffirmed the Paris Agreement and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels. The Government of Canada has pledged to cut its emissions by 40-45% from 2005 levels by 2030 and reach net zero by 2050 with the 2030 Emissions Reduction Plan. Key new actions for the oil and gas industry under this plan are capping emissions, advancing carbon capture, eliminating subsidies for fossil fuels and supporting workers.

On June 29, 2021, Bill C-12, an Act respecting transparency and accountability in Canada's efforts to achieve net-zero greenhouse gas emissions by the year 2050, received royal assent. Canada joins over 120 countries in committing to net-zero emissions by 2050, including the UK, Germany, France and Japan. Bill C-12 legally binds the federal government to a process to achieve net-zero emissions by 2050. The legislation, among other things, sets rolling five-year emissions-reduction targets (starting in 2030) and requires plans to reach each target on a reporting basis and enshrine greater accountability and public transparency into Canada's plan for meeting net-zero emissions by 2050 by providing for independent third-party review by the Commissioner of the Environment and Sustainable Development.

On December 11, 2020, the Government of Canada released its Healthy Environment and a Healthy Economy Plan (the “HEHE Plan”) which builds on the Pan-Canadian Framework and provides a road map forward to meet Canada's 2030 emissions reduction target. The HEHE Plan includes significant investments in projects to decarbonize large emitters, scale-up clean technology, accelerate industry transformation, create renewable energy, grid modernization projects, advancing the use of clean energy in rural areas, create incentives for Zero-Emission Vehicles, installing charging stations across Canada, and utilization of Low-Carbon and Zero-Emissions Fuels to increase the production of low-carbon fuels.

On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the “GGPPA”), which came into force on January 1, 2019. This regime has two parts: the OBPS and a regulatory fuel charge imposing an initial price of \$20/tonne of CO₂e emissions. This system applies in provinces and territories that request it and in those that do not have their own emissions pricing systems in place that meet the federal standards. The effect of the GGPPA is that, regardless of whether a particular province has enacted legislation of its own, there is a uniform price on emissions across the country. Any province or territory has the flexibility to design their own carbon tax pricing system, so long as it meets the minimum national stringency standards. In Alberta, a federal fuel charge under the GGPPA applies to any fuel consumption not enrolled under the provincial Technology Innovation and Emissions Reduction (TIER) system.

On April 26, 2018, the federal government passed the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (the Federal Methane Regulations). The Federal Methane Regulations seek to reduce emissions of methane from the petroleum and natural gas industry, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatons by 2030. On December 4, 2023, the Minister of Environment and Climate Change announced amendments to the Federal Methane Regulations that seek to further cut emissions, which would come into force on January 1, 2027. These amendments signify a significant reinforcement to Canada's methane strategy. The draft amendments are undergoing consultation. The Government of Alberta has opposed the amendments, stating it will take measures to ensure the amended regulations are not implemented in Alberta. It is unknown at this time what the potential effects of the amended Federal Methane Regulations may be.

On December 18, 2020, the federal government published proposed Clean Fuel Regulations (“CFS Regulations”) which requires producers, importers and distributors to reduce the emissions intensity of gaseous, liquid and solid fuels. The CFS Regulations require suppliers of liquid fuels, such as gasoline, diesel and kerosene to reduce the carbon intensity of their liquid fossil fuels. Beginning in 2023, the carbon intensity reduction requirement started at 3.5 gCO₂e/MJ, increasing by 1.5gCO₂e/MJ each year and reaching 14gCO₂e/MJ in 2030. The standard applies to any company that domestically produces or imports at least 400 cubic metres of liquid fossil fuels for use in Canada.

On December 17, 2024, the federal government finalized the Clean Electricity Regulations aimed at driving progress towards a net-zero electricity grid by 2050. The Clean Electricity Regulations are part of a suite of measures by the Government of Canada from the 2030 Emissions Reduction Plan to transition to clean energy. Developed under CERA, these regulations establish stringent pollution emission standards without prescribing specific technologies.

The Alberta Government has previously contested the constitutionality of the draft Clean Electricity Regulations and urged the federal government to support Alberta's plan for achieving carbon neutrality by 2050, rather than the initial 2035 timeline. On November 27, 2023, the Government of Alberta issued notice of its intention to invoke a resolution under the Alberta Sovereignty within a United Canada Act (the "Sovereignty Act") in response to the draft Clean Electricity Regulations. This resolution directs specific provincial entities from enforcing or complying with the Clean Electricity Regulations "to the extent legally permissible." Following the release of the final draft of the Clean Energy Regulations, in December 2024, the Government of Alberta issued a statement welcoming the extended timeline but continued to assert that the regulations strayed into provincial jurisdictions. Consequently, there is a possibility that once implemented, the Clean Electricity Regulations will face constitutional challenges.

The federal government has enacted the Multi-Sector Air Pollutants Regulation under the authority of CERA, which seeks to regulate certain industrial facilities and equipment types, including boilers and heaters used in the upstream petroleum and natural gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

On June 13, 2023, Bill S-5 Strengthening Environmental Protection for a Healthier Canada Act to amend CERA, received royal assent. The amendments include changes to the preamble of CEPA, which now recognizes that every individual in Canada has a right to a healthy environment. Section 2 of CEPA now requires that the federal government protect this right, and that an implementation framework be developed to consider how this right will be administered under CEPA, which is anticipated to be published in 2025. Further amendments include creating a risk assessment Plan of Chemical Management Priorities, setting out a multi-year assessment of substances and activities, and a commitment to consider the cumulative effects of these assessments on vulnerable populations.

Alberta Climate Change Regulations

In December 2016, the Oil Sands Emissions Limit Act (Alberta) came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed. The delay in drafting these regulations has been inconsequential thus far, as Alberta's oil sands emitted roughly 82 megatonnes of GHG emissions in 2023, well below the 100 megatonne limit.

In December 2019, the federal government approved Alberta's TIER regulation and it came into effect on January 1, 2020 (as amended on January 1, 2023) and replaced the previous Carbon Competitiveness Incentives Regulation. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, and the federal backstop continues to apply to emissions sources not covered by the regulation.

The Government of Alberta committed to lowering annual methane emissions from 2014 levels by 45% by 2025 and reached this target 3 years early. The Government of Alberta enacted the Methane Emission Reduction Regulation on January 1, 2020, and in November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("UNDRIP") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. In November 2019, the Declaration on the Rights of Indigenous Peoples Act ("DRIPA") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP.

On June 21, 2021, Bill C-15 received royal assent implementing the United Nations Declaration of the Rights of Indigenous Peoples in Canada. Canada's 2023-2028 Action Plan was released in June 2023 and included 131 measures intended to provide a roadmap of actions Canada needs to take in partnership with Indigenous peoples to implement the principles and rights set out in the UNDRIP and to further advance reconciliation in a tangible way. The practical consequences of this Action Plan remain unclear. Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and Bill C-15 are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including pipelines. See "*Risk Factors – Indigenous Rights*".

Accountability and Transparency

In 2015, the federal government's Extractive Sector Transparency Measures Act ("ESTMA") came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over \$100,000 made to any level of a Canadian or foreign government (including Indigenous groups), including royalty payments, taxes (other than consumption taxes and personal taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

Bill S-211, An Act to enact the Fighting Against Forced Child Labour in Supply Chains Act and to amend the Customs Tariff (the "Modern Slavery Act") received royal assent on May 11, 2023 and came into force on January 1, 2024. Pursuant to the Modern Slavery Act, entities that meet certain criteria are required to file public reports annually on the steps they have taken prevent and reduce the use of forced labour and child labour in their supply chains related to production or importation of goods.

RISK FACTORS

Tamarack is subject to both risks that directly affect the Company's business and operations, as well as indirect risks that impact third parties or industry. Investors should carefully consider the risk factors set out below and consider all other information contained in this AIF and the Company's other public filings before making an investment decision. The risks set out below are not exhaustive and should not be taken as a complete summary or description of all the risks associated with Tamarack's business, the business of third parties with whom the Company conducts business and the crude oil and natural gas business. If any event arising from the risk factors set forth below occurs, Tamarack's business, prospects, financial condition, results of operation or adjusted funds flows and, in some cases, its reputation could be materially adversely affected.

Volatility in the Petroleum and Natural Gas Industry

Market events and conditions, including global excess crude oil and natural gas supply, actions taken by OPEC+, sanctions against, and civil unrest in Northern Africa, Iran and Venezuela, Russia and the Ukraine, the Middle East, Israel and the West Bank and Gaza Strip and Yemen, slowing growth in China and emerging economies, market volatility and disruptions in Asia, weakening global relationships, conflict between the United States and Iran, the war in Ukraine, isolationist and punitive trade policies, increased United States shale production, sovereign debt levels, world health emergencies (including the global pandemics), environmental concerns and political upheavals in various countries, including growing anti-fossil fuel sentiment, have caused significant weakness and volatility in commodity prices. Following extreme supply/demand imbalance in 2020, the crude oil and natural gas industry rebounded strongly throughout 2021, with oil prices reaching their highest levels in six years. However, the ongoing war in the Ukraine and price caps and sanctions on oil from Russia have impacted demand and oil prices throughout the latter half of 2022 which continued throughout 2024.

Difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the petroleum and natural gas industry in Western Canada and cross-border with the United States has led to additional downward price pressure on crude oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the petroleum and natural gas industry in Western Canada. See "Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints, Pipeline Capacity and Market Access".

Lower commodity prices may also affect the volume and value of the Company's reserves rendering certain reserves uneconomic for development by lessees on the Fee Lands and operators and working interest owners on the Royalty Properties. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, lessees and working interest owners' cash flow resulting in reduced capital expenditure budgets and in turn, adversely affecting the royalty revenue received by the Company. The third parties operating on the Royalty Properties may not be able to replace their production with additional reserves which may result in the Company's production and reserves being reduced on a year over year basis. In addition to possibly resulting in a decrease in the value of the economically recoverable reserves from the Royalty Properties, lower commodity prices may also result in a decrease in the value of the infrastructure and processing facilities on such Royalty Properties, all of which could also have the effect of requiring a write down of the carrying value of the Company's crude oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions, the Company may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and/or highly dilutive terms.

Commodity Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired, discovered or produced by Tamarack is, and will continue to be, affected by numerous factors beyond its control. The Company's ability to market its crude oil and natural gas may depend upon its ability to acquire space on pipelines that deliver oil and natural gas to commercial markets or contract for the delivery of crude oil by rail (see "Industry Conditions – Pricing and Marketing in Canada" and "Risk Factors –Volatility in the Petroleum and Natural Gas Industry"). The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines, railway lines processing and storage facilities; and operational problems affecting such pipelines, railway lines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of crude oil and natural gas and many other aspects of the crude oil and natural gas business.

Crude oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East, the war in Ukraine, and ongoing credit and liquidity concerns. Prices for crude oil and natural gas are also subject to the availability of foreign markets and the ability to access such markets. Any material decline in prices or a low crude oil and natural gas price environment could result in a reduction of Tamarack's anticipated net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of Tamarack's reserves. Tamarack might also elect not to produce from certain wells at lower prices. See "Industry Conditions - Pricing and Marketing in Canada – Transportation Constraints, Pipeline Capacity and Market Access" and "Risk Factors - Volatility in the Petroleum and Natural Gas Industry".

Volatile crude oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for crude oil and natural gas producing properties, as buyers, sellers, lessors and lessees have difficulty agreeing on the value or terms of such arrangements. Price volatility also makes it difficult to budget for and project the return on potential acquisitions, divestitures or leasing opportunities. See "Risk Factors - Volatility in the Petroleum and Natural Gas Industry".

All of these factors could result in a material decrease in Tamarack's expected net production revenue and a reduction in its future crude oil and natural gas acquisition, exploration, development and production activities. Any substantial and extended decline in or a low crude oil and natural gas prices would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and adjusted funds flows from operations and may have a material adverse effect on the Company's business and financial condition. In addition, bank borrowings available to Tamarack may, in part, be determined by Tamarack's borrowing base. A sustained material decline in prices from historical

average prices could reduce Tamarack's borrowing base, therefore reducing the bank credit available to Tamarack which could require that a portion, or all, of Tamarack's bank debt be repaid.

Project Risks

The Company manages a variety of small and large projects in the conduct of its business. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. Tamarack's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including the following: processing capacity availability; availability and proximity of pipeline capacity; availability of storage capacity; availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods; the Company's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations; effects of inclement and severe weather events and natural disasters, including fire, drought and flooding; availability of drilling and related equipment; unexpected cost increases; accidental events; currency fluctuations; regulatory changes; political uncertainty; availability and productivity of skilled labour; environmental and Indigenous activism or land claims that potentially results in delays or cancellations of projects; litigation and judicial interpretation and application of laws, including with respect to Indigenous rights and historical treaties; and regulation of the oil and natural gas industry by various levels of government and governmental agencies. These factors could result in Tamarack being unable to execute projects on time, on budget, or at all and may be unable to effectively market its oil and natural gas products.

Reliance on Operators, Management and Key Personnel

The operations and management of the Company require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement the Company's business plans which could have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Tamarack's success will be, in part, dependent on the performance of its key managers and consultants. Failure to retain the managers and consultants, or to attract or retain additional key personnel, with the necessary skills and experience could have a materially adverse impact upon Tamarack's growth and profitability. Tamarack does not carry key person insurance. The contributions of the existing management team to the immediate and near-term operations of the Company are likely to be of central importance. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company. In addition, Tamarack may not be the operator of certain oil and natural gas properties in which it acquires an interest. To the extent Tamarack is not the operator of its oil and natural gas properties, Tamarack will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators.

Third-Party Credit Risk and Delays

Tamarack is or may be exposed to third-party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production, suppliers and other parties. In the event such entities fail to meet their contractual obligations to Tamarack, such failures could have a material adverse effect on Tamarack and its adjusted funds flow. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in Tamarack's ongoing capital program, potentially delaying the program and the result of such program until Tamarack finds a suitable alternative partner.

In addition to the usual delays in payments by purchasers of oil and natural gas to Tamarack or to the operators, and the delays by operators in remitting payment to Tamarack, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale of delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of adjusted funds flow available for the business of Tamarack in a given period and expose Tamarack to additional third-party credit risks. To the extent that any such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Company being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Company's business and financial condition.

Alternatives to, and Changing Demand for, Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for crude oil and other liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels, commitments to carbon reduction and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for crude oil and natural gas products. Tamarack cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a negative effect on Tamarack's business, financial condition, results of operations and adjusted funds flows.

Variations in Foreign Exchange Rates and Interest Rates

Operating costs incurred by Tamarack are generally paid in Canadian dollars. World crude oil and natural gas prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which fluctuates over time. In 2024 and the first month of 2025, the Canadian dollar lost 7% against U.S. dollar, reaching its lowest level since 2020. Material increases in the value of the Canadian dollar negatively impact Tamarack's production revenues. Future Canadian/U.S. exchange rates could accordingly impact the future value of Tamarack's reserves as determined by independent reserves evaluators. Although a low value of the Canadian dollar relative to the U.S. dollar may positively impact the price the Company receives for crude oil and natural gas production it could also result in an increase in the price of certain goods used in operations which may have a negative impact on the Company's financial results. Where the Company engages in risk management activities related to foreign exchange rates, there is a potential credit risk associated with counterparties with which the Company may contract. To the extent that Tamarack engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which Tamarack may contract. Further increases in interest rates could result in increases in the amount

Tamarack pays to service debt, which could negatively impact the market price of the Common Shares, this negative impact could prove to be material over time.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Tamarack depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves Tamarack may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Tamarack's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that Tamarack will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, Tamarack may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by Tamarack.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents and the shutting-in of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect production and reduce the Company's revenue.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including but not limited to hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills and other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including geological and seismic risks, encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a negative effect on future results of operations, liquidity and financial condition, which could prove to be material over time. As is standard industry practice, Tamarack is not fully insured against all risks, nor are all risks insurable. Although the Company maintains liability insurance in an amount considered consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, Tamarack could incur significant costs. See "Risk Factors – Insurance".

Gathering and Processing Facilities, Pipeline Systems and Rail

The products Tamarack produces must be delivered through gathering, processing and pipeline systems, some of which are not owned by the Company, and in certain circumstances, by rail. The amount of crude oil and natural gas produced and sold from Tamarack's assets is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits, and limits on availability of capacity in gathering and processing facilities continues to affect the petroleum and natural gas industry and limits the ability to transport produced crude oil and natural gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of crude oil and natural gas companies to export oil and natural gas. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work, natural disasters and environmental conditions, or because of actions taken by regulators could also affect third parties' production and operations which may have a material adverse effect on the Company's business and financial condition. As a result, producers have considered rail lines as an alternative means of transportation.

Federal and various provincial governments have been active in recent years in their support for and opposition to major infrastructure projects in Canada, leading to increased awareness and challenges to interprovincial and international infrastructure projects. On August 28, 2019, with the passing of Bill C-69, the CERA and the IAA came into force and the NEB Act and the CEAA 2012 were repealed. In addition, the IA Agency replaced the CEA Agency. See "Industry Conditions - Regulatory Authorities and Environmental Regulation". The impact of the new federal regulatory scheme on proponents and the timing for receipt of approvals of major projects is unclear as few projects have been tested under this legislative scheme. Projects which are subject to an impact assessment under the IAA, and other revamped provincial legislation, will be subject to a robust assessment of the environmental, social, health, economic and cultural impacts of a proposed project subject to the legislation, as well as the effects of projects on Indigenous peoples and their rights which may lead to longer periods to conduct the assessment and potentially more opportunities for public engagement and consultation.

A portion of Tamarack's production is processed through facilities owned by third parties over which the Company has no control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of third-party facility operations could have a materially adverse effect on Tamarack's production and ability to deliver the same for sale, which, in turn, would indirectly reduce the Company's revenues. Midstream and pipeline companies may take actions

to maximize their return on investment which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Regulatory

Crude oil and natural gas operations (exploration, development, production, pricing, marketing, transportation and infrastructure) are subject to extensive controls and regulations imposed by various levels of government and may be amended from time to time. Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of crude oil and natural gas and infrastructure projects. Amendments to these controls and regulations, including changes to royalty regimes or the calculation of production and mineral taxes, may occur from time to time in response to economic or political conditions. See "Industry Conditions". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Company's costs, or make certain projects on the Company's assets uneconomic, which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Further, the ongoing third-party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime as the implementation of the orders can be delayed resulting in uncertainty and interruption to business of the crude oil and natural gas industry. See "Industry Conditions - Climate Change Regulations". Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and natural gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact crude oil and natural gas operations and may affect the Company's business and financial condition. See "Industry Conditions – Federal Climate Change Regulation" and "Industry Conditions – Alberta Climate Change Regulation".

Tamarack's operations require regulatory permits, licences, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that Tamarack will be able to obtain all necessary permits, licences, registrations, approvals and authorizations to carry out exploration and development at its projects. In addition, certain federal legislation such as the Competition Act (Canada) and the Investment Canada Act could negatively affect the Company's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. It is not expected that any of these controls or regulations will affect the operations of Tamarack in a manner materially different from how they would affect other oil and natural gas companies of similar size. See "Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Programs".

Environmental Regulation

All phases of the oil and gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and municipal laws. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. See "Industry Conditions – Exports from Canada", "Industry Conditions – Regulatory Authorities and Environmental Regulation" and "Industry Conditions – Climate Change Regulation".

Compliance with environmental legislation can require significant expenditures and a breach of such legislation may result in the imposition of fines or other penalties, some of which may be material, as well as the responsibility to remedy environmental problems caused by Tamarack's operations. See "Industry Conditions – Regulatory Authorities and Environmental Regulation". Should Tamarack be unable to fully fund the cost of remedying an environmental problem, Tamarack might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require Tamarack to incur costs to remedy such discharge. Although Tamarack believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect Tamarack's financial condition, results of operations or prospects. See "Industry Conditions – Regulatory Authorities and Environmental Regulation".

Liability Management

Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its regulatory obligations. Alberta and the AER has implemented the AB LMF replacing the current Alberta Liability Management Program. The continued implementation of the AB LMF Program or other changes to the requirements of liability management programs may result in significant increases to the security that must be posted by such third parties, increased and more frequent financial disclosure obligations or may result in the denial of licence or permit transfers, which could impact the availability of capital to be spent by them which could in turn materially adversely affect the Company's business and financial condition. The impact and consequences of the SCC's decision in Redwater on the AER's rules and policies, lending practices in the petroleum and natural gas industry and on the nature and determination of secured lenders to take enforcement proceedings are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMF may prevent or interfere with a third party's ability to acquire or dispose of assets, as both the vendor and the purchaser of crude oil and natural gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "Industry Conditions – Regulatory Authorities and Environmental Regulation" and "Industry Conditions – Liability Management Programs".

Royalty Regimes

There can be no assurance that the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Company's projects. An increase in royalties would reduce the Company's

earnings and could make future capital investments, or Tamarack's operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See "Industry Conditions – Royalties Regime in Canada".

Pandemic Risk

Severe disruptions in regional economies and the world economy can be caused by the outbreak of a contagious illness. Such pandemics and efforts to contain them could result in international, national and local border closings, travel restrictions, significant disruptions to business operations, supply chains, customer activity and demand, service cancellations, reductions and other changes, significant challenges in healthcare service preparation and delivery, and quarantines, as well as considerable general concern and uncertainty, all of which could negatively affect the economic environment and may in the future have further impacts, as was the case for the COVID-19 pandemic. It is not possible to predict what measures and restrictions may be imposed by governmental authorities and the period of time during which those measures and restrictions may apply. Economic and supply chain disruptions, including temporary staff shortages resulting from a pandemic, could further materially affect the Company's financial results and operations. A pandemic could also further and significantly impact global economic activity, including demand for hydrocarbons, and cause increased market volatility, continued changes to the macroeconomic environment and commodity prices in connection with ensuing economic disruption, supply shortages, trade disruption, temporary staff shortages and temporary closures of facilities in geographic locations more importantly impacted by the outbreak. The scope and severity of such disruptions and their impact on the Company's financial results and operations could be material.

Climate Change Policy Risks

Foreign and domestic governments continue to evaluate and implement policy, legislation and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. The majority of countries, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. At the 2021 UN Climate Change Conference, Canada made several pledges aimed at reducing Canada's GHG emissions and at the 2024 UN Climate Change Conference, Canada reaffirmed its commitments to transitioning away from fossil fuels and further cutting GHG emissions. Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing operating expenses, and, in the long-term, potentially reducing the demand for crude oil and natural gas and related products, resulting in a decrease in the Company's profitability and a reduction in the value of its assets. See "Risk Factors – Non-Governmental Organizations", and "Risk Factors – Reputational Risk".

With respect to environmental, social, governance and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators published for comment Proposed National Instrument 51-107 - Disclosure of Climate-related Matters, intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If the Company is not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, its business and ability to attract and retain skilled employees, obtain regulatory permits, licences, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected.

Given the evolving nature of climate change policy and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing the Company's operating expenses and in the long-term, potentially reducing the demand for crude oil and natural gas production resulting in a decrease in the Company's profitability and a reduction in the value of its assets or requiring impairments for financial statement purposes. See "Industry Conditions – Climate Change Regulation", "Risk Factors – Non-Governmental Organizations", "Risk Factors – Reputational Risk" and "Risk Factors – Changing Investor Sentiment".

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under high pressure into rock formations to stimulate the production of crude oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Certain areas in Alberta and other provinces have been prone to seismic activity and as a result, additional protocols relating to hydraulic fracturing and seismic monitoring have been implemented in such areas. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the costs of compliance and doing business as well as delay the development of crude oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of crude oil and natural gas that is ultimately produced from the reserves associated with Tamarack's assets and, therefore, could materially adversely affect the Company's business, financial condition, results of operations and prospects.

Water is an essential component of Tamarack's drilling and hydraulic fracturing processes. Limitations or restrictions on Tamarack's ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact its operations. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If Tamarack is unable to obtain water to use in its operations from local sources, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Cost increases could have a material adverse effect on drilling economics resulting in delays or suspensions of drilling which ultimately may have a detrimental effect on Tamarack's financial condition, results of operations, and cash flows.

Volatility of Market Price of Common Shares

The trading price of securities of crude oil and natural gas producers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. The volatility may affect the ability of holders to sell the Common Shares at an advantageous price. Factors unrelated to the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices and/or current perceptions of the crude oil and natural gas market. This includes, but is not limited to, changing and in some cases, negative investor sentiment towards energy-related businesses. In recent years, the volatility of crude oil and natural gas commodity prices, and the securities of issuers involved in the crude oil and natural gas business, has increased due, in

part, to the implementation of computerized trading and the decrease of discretionary commodity trading. Similarly, recent market prices in the securities of crude oil and natural gas issuers relative to other industry sectors have led to lower crude oil and natural gas representation in certain key equity market indices. The volatility, trading volume and market price of crude oil and natural gas have been impacted by increasing investment levels in passive funds that track major indices and only purchase securities included in such indices and subsequently dispose of those securities if they are excluded from such indices. In addition, many institutional investors, pension funds and insurance companies, including government sponsored entities, have implemented investment strategies increasing their investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments. These factors have impacted the volatility and liquidity of certain securities and put downward pressure on the market price of those securities. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted. Similarly, the market price of the Common Shares may be due to Tamarack's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by Tamarack or its competitors, along with a variety of additional factors, including, without limitation, those set forth under "Forward-Looking Statements". In addition, in recent years the market price for securities in the stock markets, including the TSX, experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that often has been unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market prices of the Common Shares. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Credit Facility and senior unsecured notes Arrangements

The amount authorized under the Credit Facility is determined by the lenders to Tamarack. The amounts drawn on the Credit Facility will fluctuate from time to time depending on the cash needs of the business. The amounts authorized and outstanding under the senior unsecured notes are fixed, with scheduled repayments, as determined by the indentures. The Company is required to comply with financial and other covenants under the Credit Facility, and the indentures governing the Senior unsecured notes and is subject to certain financial ratio tests, which from time to time, either affect the availability, or price, of additional funding and in the event that the Company does not complete therewith, the Company's access to capital could be restricted or repayment could be required. The failure of the Company to comply with such covenants, which may be affected by events beyond the Company's control, could result in the default under the Credit Facility or the Senior unsecured notes, which could result in the Company being required to repay amounts owing thereunder. Even if the Company is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Company. If the Company is unable to repay amounts owing, the lenders to Tamarack under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Company's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default and cross-acceleration provisions. In addition, the Credit Facility and the Senior unsecured notes may, from time to time, impose operating and financial restrictions on the Company that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Company's securities, incurring of additional indebtedness, provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

Borrowing

From time to time, Tamarack may acquire assets or the shares of other corporations or otherwise finance its ongoing operations using debt, which may increase Tamarack's debt levels above industry standards. Further, a significant decrease in crude oil and natural gas prices, hedging losses or lower than expected production from Tamarack's properties may cause the Company's net debt to trailing annual adjusted funds flow to rise above its peer standards. The level of Tamarack's indebtedness or net debt to trailing annual adjusted funds flow from time to time could impair Tamarack's ability to obtain additional financing in the future on a timely basis and could affect the market price of the Common Shares.

Substantial Capital Requirements

Tamarack anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Company's ability to do so is dependent on, among other factors: the overall state of the capital markets; the Company's credit rating; commodity prices; interest rates; royalty rates; tax burden due to current and future tax laws; and investor appetite for investments in the energy industry and Tamarack's securities in particular. Further, if the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. Tamarack may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on its business financial condition, results of operations and prospects.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, Tamarack may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Company may from time to time have restricted access to capital and increased borrowing costs. As a result of global economic and political volatility, Tamarack may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If revenues from the Company's reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect Tamarack's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become

limited, unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely. In addition, the future development of Tamarack's properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing could be highly dilutive to existing shareholders. Failure to obtain any financing necessary for Tamarack's capital expenditure plans may result in a delay in development or production on the Company's properties.

Changing Investor Sentiment

A number of factors, including perceptions relating to the use of fossil fuels on GHG emissions reduction, the impact of crude oil and gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors' sentiments towards investing in the crude oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in crude oil and natural gas properties or companies tied to crude oil and natural gas or are reducing the amount of their investments of such entities over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices, including the use of environmental metrics in executive compensation. Developing and implementing such policies and practices can be costly and require a significant time commitment from the Board, management and employees of the Company. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Company or not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the crude oil and natural gas industry, and more specifically, the Company, may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares, even if the Company's operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of the Company's assets which may result in an impairment change.

Evolving Corporate Governance, Sustainability and Reporting Framework

The Company's business is subject to evolving corporate governance and public disclosure regulations that have increased both compliance costs and the risk of noncompliance, which could have an adverse effect on the price of the Company's securities. Tamarack is subject to changing rules and regulations promulgated by a number of governmental and self-regulated organizations, including the Canadian Securities Administrators, the TSX and the Financial Accounting Standards Board. These rules and regulations continue to evolve in scope and complexity making compliance more difficult and uncertain. Further, the Company's efforts to comply with these and other new and existing rules and regulations have resulted in, and are likely to continue to result in, increased general and administrative expenses and a diversion of management time and attention from revenue-generating activities to compliance activities.

Reputational Risk

The Company's business, financial condition, operations or prospects may be negatively impacted as a result of any negative public opinion toward Company or as a result of any negative sentiment toward or in respect of Company's reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Company operates as well as their opposition to certain crude oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences and increased costs and/or cost overruns. Any environmental damage, loss of life, injury or damage to property caused by Tamarack's operations could damage the reputation of the Company in active operational areas. The Company's reputation could be affected by actions and activities of other corporations operating in the crude oil and natural gas industry, over which the Company has no control. If the Company, either directly or indirectly, develops a reputation of having an unsafe work site it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against fossil fuel companies may indirectly harm the Company's reputation. In addition, environmental damage, loss of life, injury or damage to property caused indirectly by the Company's operations could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares. Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard the Company's reputation. Damage to the Company's reputation could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Company's securities.

Dividends

The amount of future cash dividends paid by the Company is subject to the discretion of the Board and may vary depending on a variety of factors and conditions existing from time to time, including, among other things, fluctuations in commodity prices; production levels; financial condition; current and expected future levels of earnings; liquidity requirements; market opportunities; income taxes; debt repayments; legal, regulatory, and contractual constraints; tax laws; foreign exchange rates; and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Company, the dividend policy of the Company from time to time and, as a result, future cash dividends could be reduced or suspended entirely. The Credit Facility may prohibit the Company from paying dividends at any time at which a default or event of default has occurred and is continuing, or if a default or event of default would exist as a result of paying the dividend. Over time, the Company's capital and other cash needs may change significantly from its current needs, which could affect whether the Company pays dividends and the amount of dividends, if any, it may pay in the future. If the Company continues to pay dividends at the current levels, it may not retain a sufficient amount of cash to finance external growth opportunities, meet any large unanticipated liquidity requirements or fund its activities in the event of a significant business downturn. The Board may amend, revoke or suspend the Company's dividend policy at any time. A decline in the market price or liquidity, or both, of the Common Shares could result if the Company reduces or eliminates the payment of dividends, which could result in

losses to shareholders. The market value of the Common Shares may deteriorate if cash dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by the Company and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by the Company to finance capital expenditures using funds from operations. To the extent that the Company is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Foreign Exchange Risk on Dividends

The Company's cash dividends are declared in Canadian dollars and may be converted in certain instances to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, non-resident shareholders, and shareholders who calculate their return in currencies other than the Canadian dollar, are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to the shareholder's home currency.

Inflation and Cost Management

The Company's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. Tamarack's inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on the Company's financial performance and funds from operations. The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to Tamarack's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and funds from operations.

Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and cash flows to be derived therefrom, including many factors beyond Tamarack's control. The information concerning reserves and associated cash flow set forth in this AIF represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as: historical production from the properties; production rates; ultimate reserve recovery; timing and amount of capital expenditures; marketability of oil and natural gas; royalty rates; the assumed effects of regulation by governmental agencies; and future operating costs, all of which may vary from actual results.

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. Tamarack's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material. Further, the evaluations are based, in part, on the assumed success of the exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material. Many of Tamarack's producing wells have a limited production history and thus there is less historical production on which to base the reserves estimates. In addition, a significant portion of Tamarack's reserves may be attributable to a limited number of wells and, therefore, a variation in production results or reservoir characteristics in respect of such wells may have a significant impact upon Tamarack's reserves.

In accordance with applicable securities laws, McDaniel and GLJ have used forecast price and cost estimates based on averages from three different independent evaluators' price forecasts in calculating reserves quantities. See "Statement of Reserves Data and Other Oil and Gas Information – Pricing Assumptions". Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs. Actual production and cash flows derived therefrom will vary from the estimates contained in the McDaniel and GLJ Reports and such variations could be material. The McDaniel and GLJ Reports are based in part on the assumed success of activities Tamarack intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the McDaniel and GLJ Reports will be reduced to the extent that such activities do not achieve the level of success assumed in the McDaniel and GLJ Reports. The McDaniel and GLJ Reports are effective as of December 31, 2024, with a preparation date of January 20, 2025 in respect of the McDaniel Report and January 8, 2025 in respect of the GLJ Report, and, except as may be specifically stated or required by applicable securities laws, has not been updated and, therefore, does not reflect changes in reserves since that date.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise. The actual interest of the Company in properties may accordingly vary from Tamarack's records. If a title defect does exist, it is possible that the Company may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Company's title to the oil and natural gas properties Tamarack controls that could impair the Company's activities on them and result in a reduction of the revenue.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

Tamarack makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Acquisitions of oil and natural gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquirer, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of Tamarack. All such assessments involve a measure of geologic, engineering, facility operations, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as Tamarack's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of so that Tamarack can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of Tamarack, if disposed of, could be expected to realize less than their carrying value on the financial statements.

Hedging

From time to time, Tamarack may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; similarly, the Company may enter into agreements to fix the differential or discount pricing gap which exists, and may fluctuate between different grades of crude oil, NGL and natural gas and the various market prices received for such products. However, if commodity prices or differentials increase beyond the levels set in such agreements, Tamarack may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. In addition, if the Company enters into hedging arrangements it may be exposed to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes or prices fall significantly lower than projected; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement; the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; and/or a sudden unexpected material event impacts crude oil and natural gas prices. Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to U.S. dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Company will not benefit from the fluctuating exchange rate. Tamarack management meets weekly to review hedging strategies and market conditions. The Company's active risk management incorporates financial hedging in accordance with the Company's Hedging Policy.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. Tamarack will actively compete for capital, skilled personnel, access to rigs and other equipment, access to processing facilities and pipeline and refining capacity and in all other aspects of its operations with a substantial number of other organizations. In addition, the Company competes with numerous other entities in the search for, and the acquisition of, petroleum and natural gas properties and in the marketing of petroleum and natural gas. In particular, the Company competes with other companies for the acquisition of royalty interests in petroleum and natural gas properties. Other companies may have access to substantially greater financial resources, staff, political influence or facilities than those of the Company and who may have lower costs of, and better access to, capital. The Company's ability to increase its reserves in the future will depend partially on its and its partners' and royalty payors' ability to explore and develop its present properties but will primarily depend on its ability to acquire royalty interests in suitable producing properties or properties with future reserve or resource potential.

Political Uncertainty

The Company's results can be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact Tamarack's existing operations and planned projects. This includes actions by regulators or other political factors to delay or deny necessary licenses and permits for the Company's activities or restrict the operation of third-party infrastructure that the Company relies on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact Tamarack's results.

Other government and political factors that could adversely affect the Company's financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements, including tariffs. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could affect the Company's operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand for the Company's products.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the petroleum and natural gas industry including the balance between economic development and environmental policy. Lack of political consensus, at both the federal and provincial government level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the petroleum and natural gas industry, which effect could prove to be material

over time. See "Industry Conditions – Climate Change Regulation", "Industry Conditions – Pricing and Marketing in Canada – Transportation Constraints, Pipeline Capacity and Market Access – Specific Pipeline Updates", and "Industry Conditions – Trade Agreements".

Danielle Smith was elected as Premier on October 11, 2022. Shortly after her appointment, Premier Smith introduced Bill 1: The Alberta Sovereignty Within a United Canada Act (the Sovereignty Act). The Sovereignty Act was passed on December 8, 2022, and received Royal Assent on December 15, 2022. The Sovereignty Act, amongst other things, enables the Alberta Government to choose which federal legislation, policies or programs it will enforce in Alberta, providing an overriding right to not enforce those which the Alberta Government deems to be "harmful" to Alberta's interests or infringe on the Federal Constitution and its division of powers. The Sovereignty Act has been opposed by many, including the National Democratic Party and various Indigenous groups who have expressed concern as to how the Sovereignty Act will affect Indigenous rights and consultation obligations in Alberta. In November 2023, the Government of Alberta introduced a resolution to invoke the Sovereignty Act to challenge the federal government's requirement for a net-zero electricity grid by 2035. It is unclear what the effect the Sovereignty Act will have on Alberta, including the petroleum and natural gas industry, Alberta businesses and its federal and interprovincial relationships, including the application of certain federal legislation in Alberta, such as the GGPPA and the IAA and the way in which the Alberta Government may address any legislative and policy gaps created. Although the Sovereignty Act has not yet been challenged in court, it is possible the Sovereignty Act's constitutionality will be challenged.

Geopolitical Risks

The marketability and price of oil and natural gas that may be acquired or discovered by Tamarack is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or parties in power, may have a significant impact on the price of crude oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of Tamarack's net production revenue. The level of geopolitical risk escalates at certain points in time. While the specific impact on the global economy would depend on the nature of the event, in general, any major event could result in instability and volatility. Current areas of concern include: global uncertainty and market repercussions due to the spread of global pandemics; Russia's military invasion of Ukraine; the Israeli-Hamas conflict and rising civil unrest; fall of the Syrian Assad regime and uncertainty regarding the transitional government; and activism globally.

Non-Governmental Organizations

The oil and gas exploration, development and operating activities conducted by Tamarack may, at times, be subject to public opposition. Such public opposition could expose Tamarack to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenous groups, landowners, environmental interest groups (including those opposed to oil and gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, and delays in, challenges to, or the revocation of regulatory approvals, permits and/or licences and direct legal challenges, including the possibility of climate-related litigation (see "Industry Conditions – Transportation Constraints, Pipeline Capacity and Market Access"). There is no guarantee that the Company will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require significant and unanticipated capital and operating expenditures which may negatively impact the Company's business, financial condition, results of operations and prospects. In addition, the Company's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack which may have a material adverse effect on its business, financial condition, results of operations and prospects. Tamarack does not have insurance to protect against the risk of terrorism.

Waterflood

Tamarack undertakes or intends to undertake certain waterflooding programs which involve the injection of water or other liquids into an oil reservoir to increase production from the reservoir and to decrease production declines. To undertake such waterflooding activities the Company needs to have access to sufficient volumes of water, or other liquids, to pump into the reservoir to increase the pressure in the reservoir. There is no certainty that there will be access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as waterflooding. If the Company is unable to access such water it may not be able to undertake waterflooding activities, which may reduce the amount of oil and natural gas that can ultimately be produced from the reservoirs. In addition, the Company may undertake certain waterflood programs that ultimately prove unsuccessful in increasing production from the reservoir and as a result have a negative impact on the Company's business, financial condition, results of operations and prospects.

Disposal of Fluids Used in Operations

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from crude oil and natural gas wells is subject to ongoing regulatory review by federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the costs of compliance for Tamarack which may impact the economics of certain projects and in turn impact activity levels and new capital spending on the Company's properties.

Cost of New Technologies

The petroleum industry is characterized by rapid technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to implement and benefit from technological advantages. There can be no assurance that Tamarack will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If Tamarack implements such technologies, there is no assurance that the Company will do so successfully. One or more of the technologies currently utilized by Tamarack or implemented in the future may become obsolete. In such case, the Company's business, financial condition and results of operations could be materially adversely affected. If Tamarack is unable to utilize the most advanced commercially available technology, or it is unsuccessful in implementing certain technologies, the Company's business, financial condition and results of operations could be materially adversely affected.

Availability and Cost of Equipment, Material and Qualified Personnel

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment, including drilling and related equipment and qualified personnel in the particular areas where such activities will be conducted. Demand for such limited equipment and qualified personnel may affect the availability of such equipment and qualified personnel to Tamarack and may delay Tamarack's exploration and development activities. A decline in market conditions has led increasing numbers of skilled personnel to seek employment in other industries. In addition, the costs of qualified personnel and equipment in the areas where the assets are located are very high due to the availability of, and demands for, such qualified personnel and equipment.

Management of Growth

Tamarack may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of Tamarack to manage future growth and integration of additional lands, assets and acquisitions effectively will require it to continue to implement and improve its operations and financial systems and to expand, train and manage its employee base. The inability of Tamarack to deal with this integration growth could have a material adverse impact on its business, financial condition, operations and prospects.

Expiration of Licences and Leases

Tamarack's properties are held in the form of licences and leases and working interests in licences and leases. If the Company or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Company's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on Tamarack's business, financial condition, results of operations and prospects.

Income Taxes

Tamarack files all required income tax returns and believes that it is in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable. Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that affects the Company. Furthermore, tax authorities having jurisdiction over Tamarack may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company's detriment.

Conflicts of Interest

Certain directors and officers of Tamarack are also, or may in the future be, directors or officers of other crude oil and natural gas companies, that may compete or be counterparties to agreements with the Company and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA and the Company's policies which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract, or material transaction, or proposed material transaction, with the Company disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. The Company also has additional policies in place which require management to seek approvals of independent directors in certain situations where there may be a perceived or potential conflict of interest arising due to interlocking directorships, despite the transaction being within management's authorization levels and not otherwise requiring Board approval. See "Directors and Officers – Conflicts of Interest".

Seasonality and Extreme Weather Conditions

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may make the ground unstable, limit access and, as a result, cause reduced operations or a cessation of operations. Municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment during periods of wet weather, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict access to Tamarack's properties and cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and also to volatility in commodity prices as the demand for natural gas typically fluctuates during cold winter months and hot summer months.

Dilution

The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Company which may be dilutive.

Indigenous Rights

Indigenous peoples have rights and title in portions of Western Canada. Consultation delays, claims or objections related to Indigenous rights may disrupt or delay third-party operations, new development or new project approvals on the Company's properties. Tamarack is not aware that any claims have been made in respect of Tamarack's assets; however, if a claim arose and was successful this could have an adverse effect on Tamarack and its operations. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time. Moreover, in recent years there has been increasing litigation regarding historical treaties with Indigenous peoples in Canada. Judicial interpretation of such historical treaties, and in particular the rights granted thereunder to Indigenous nations to manage and use the lands in a manner consistent with their ancestral practices, may impact future resource and industrial development in and around these lands. While the potential impact of current and future judicial decisions is uncertain at this time, it is possible that such decisions may have a negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system, which was upheld by the SCC as constitutional, currently applies in provinces and territories without their own system that meets federal stringency standards and provinces with their own system are subject to continued compliance with the federal system. There is no guarantee that a province with a system that currently applies will meet or continue to meet federal stringency standards. See "Industry Conditions – Climate Change Regulation". The taxes placed on carbon emissions may have the effect of decreasing the demand for crude oil and natural gas products and at the same time, increasing the operating expenses of crude oil and natural gas companies, each of which may have a material adverse effect on the Company's revenue. Further, the imposition of carbon taxes puts the Company at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Insurance

Tamarack's involvement in the exploration for and development of oil and natural gas properties may result in Tamarack becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although Tamarack has obtained insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be insurable or, in certain circumstances, Tamarack may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of such uninsured liabilities would reduce the funds available to Tamarack. The occurrence of a significant event that Tamarack is not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on Tamarack's financial position, results of operations or prospects.

Impact of U.S. Legislative and Regulatory Policies

The recent election of President Trump may result in legislative and regulatory changes that could have an adverse effect on Tamarack and its financial condition. In early February 2025, the U.S. announced a 25% broad-based tariff on goods exported out of Canada into the United States, other than energy products (including oil and natural gas), which would be subject to a 10% tariff. In response, the Canadian government announced that it would impose a 25% tariff on \$155 billion of goods imported from the U.S. The U.S. subsequently announced a 25% tariff on goods imported from Mexico, a 10% tariff on goods imported from China, a 25% tariff on all global US imports of steel and aluminum, including finished metal products. Representatives of the U.S. government have publicly stated that they are considering imposing further tariffs on other goods imported from other countries. Prior to the U.S. tariffs on Canadian and Mexican goods becoming effective, they were paused for a month pending further negotiations.

In particular, there is uncertainty regarding U.S. tariffs and support for existing treaty and trade relationships, including with Canada. Implementation by the U.S. government of new legislative or regulatory policies could impose additional costs on Tamarack, decrease U.S. demand for Tamarack's products, or otherwise negatively impact Tamarack, which may have a material adverse effect on Tamarack's business, financial condition and operations. Furthermore, there is a risk that the tariffs imposed by the U.S. on other countries will trigger a broader global trade war. This uncertainty may adversely impact: (i) the ability of companies to transact business with companies such as Tamarack; (ii) Tamarack's profitability; (iii) regulation affecting the Canadian oil and gas industry; (iv) global stock markets (including the TSX); and (v) general global economic conditions. All of these factors are outside of Tamarack's control, but may nonetheless lead Tamarack to adjust its strategy in order to compete effectively in global markets.

Litigation

In the normal course of Tamarack's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, property damage, property taxes, land rights, environmental issues and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to Tamarack and as a result, could have a material adverse effect on Tamarack's assets, liabilities, business, financial condition and results of operations. Even if Tamarack prevails in any such legal proceeding, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from the Company's business operations, which could adversely affect its financial condition.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to the business, operations or affairs of Tamarack. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information by the Company, a breach could put Tamarack at competitive risk and may cause significant damage to its business. The harm to the Company's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable solely in monetary damages. There is no assurance that, in the event of a breach of confidentiality, the Company will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent any damage to its business that such a breach of confidentiality may cause.

Information Technology Systems and Cyber-Security

Tamarack has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure, and its ability to expand and continually update this infrastructure, to conduct daily operations. Various information technology systems are relied upon to estimate reserve quantities, process and record financial data, manage the land base, manage financial resources, analyze seismic information, administer contracts and communicate with employees and third-party partners.

The Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of Tamarack's information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to its business activities or competitive position. In addition, cyber-phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames,

passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Company becomes a victim to a cyber-phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information or could result in a loss of control of the Company's technological infrastructure or financial resources. The Company's employees are often the targets of such cyber-phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to the Company's computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

The Company maintains policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conducts annual cyber security risk assessments. The Company also employs encryption protection of its confidential information, all computers and other electronic devices. Despite the Company's efforts to mitigate such phishing attacks through education and training, phishing activities remain a serious problem that may damage our information technology infrastructure. The Company applies technical and process controls in line with industry-accepted standards to protect its information assets and systems, including written incident response plan for responding to a cyber security incident. However, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on the Company's performance and earnings, as well as reputation. Tamarack applies technical and process controls in line with industry-accepted standards to protect information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition and results of operations.

Social Media

Increasingly, social media is used as a vehicle to carry out cyber-phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into the Company's systems and obtain confidential information. The Company periodically reviews, supervises, retains and maintains the ability to retrieve social media content. Despite these efforts, as social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that the Company may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

Limited Ability of Residents in the U.S. to Enforce Civil Remedies

The Company is a corporation formed under the laws of Alberta, Canada and has its principal place of business in Canada. All of our directors and all of our officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all of our assets and all or a substantial portion of the assets of such persons are located outside the U.S. As a result, it may be difficult for investors in the U.S. to effect service of process within the U.S. upon such directors, officers and representatives of experts who are not residents of the U.S. or to enforce against them judgments of the U.S. courts based upon civil liability under the U.S. federal securities laws or the securities laws of any state within the U.S. There is doubt as to the enforceability in Canada against the Company or against any of our directors, officers or representatives of experts who are not residents of the U.S., in original actions or in actions for enforcement of judgments of U.S. courts of liabilities based solely upon the U.S. federal securities laws or securities laws of any state.

Forward-Looking Information May Prove Inaccurate

Current and prospective investors are cautioned not to place undue reliance on forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumptions and uncertainties are found in this AIF under the heading "Forward-Looking Statements".

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that the Company is or was a party to, or that any of its property is or was a subject of, during the most recently completed financial year that were or are material to the Company, nor are any such legal proceedings known to the Company to be contemplated which could be deemed material to the Company. To the knowledge of management of the Company, there have not been any penalties or sanctions imposed against the Company by a court relating to securities legislation or by a securities regulatory authority during the most recently completed financial year, nor have there been any other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision, and the Company has not entered into any settlement agreement before a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

To the knowledge of the directors and officers of the Company, none of the directors or executive officers of the Company, nor any person or Company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Common Shares, nor any of their respective associates or affiliates, has or has had any material interest, direct or indirect, in any transaction within the three most recently completed financial years or during the Company's current year or in any proposed transaction which has materially affected or is reasonably expected to materially affect the Company. Sony Gill, the Corporate Secretary of the Company, is a partner of the national law firm Stikeman Elliott LLP, which law firm rendered legal services to the Company.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar of the Common Shares of the Company is Odyssey Trust Company at its office in Calgary, Alberta.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, no material contracts were entered into by the Company during the most recently completed financial year nor are any material contracts in effect that were entered into prior to the beginning of the most recently completed financial year.

INTERESTS OF EXPERTS

Reserves estimates contained in this AIF were derived from the McDaniel and GLJ Reports prepared by McDaniel and GLJ, independent reserves evaluators. As of January 20, 2025 and January 8, 2025, to the knowledge of the Company, the directors, officers, employees and consultants of McDaniel and GLJ who participated in the preparation of the McDaniel Report or GLJ Report, respectively, who were in a position to directly influence the preparation or outcome of the preparation of the McDaniel and GLJ Reports, as a group, owned, directly or indirectly, less than 1% of the outstanding Common Shares. In addition, none of the officers, directors, employees or consultants of McDaniel or GLJ are or are currently expected to be elected, appointed or employed as a director, officer or employee of the Company or any of the Company's associates or affiliates.

KPMG LLP, Chartered Professional Accountants, are the auditors of the Company and have confirmed that they are independent with respect to the Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

Other than as set out above, no other experts (whose profession or business gives authority to a report, valuation, statement or opinion made by them) were named in any securities disclosure document filed by the Company pursuant to NI 51-102 in the most recently completed financial year.

ADDITIONAL INFORMATION

Additional information regarding Tamarack may be found on SEDAR+ at www.sedarplus.ca. Additional information, including directors' and officers' remuneration and indebtedness, the principal holders of Common Shares and the securities authorized for issuance under equity compensation plans, is contained in the Company's management information circular dated March 21, 2023 relating to the annual meeting of shareholders held on May 10, 2023. Additional financial information is available in the annual audited financial statements of the Company and the related management's discussion and analysis for the financial year ended December 31, 2023.

STANDARD DEFINITIONS

Throughout this AIF the terms set forth below have the following meanings, unless the context requires or indicates otherwise:

- "2019 Regulations" refers to the federal government's updated regulations which came into force on August 1, 2019.
- "AB IR Program" refers to the new Inventory Reduction Program;
- "AB LCA" means the Licensee Capability Assessment System;
- "AB LM Program" means the new Licensee Management Program;
- "AB LMF" means the Government of Alberta's Liability Management Framework;
- "AB OWL Program" means Alberta Oilfield Waste Liability Program;
- "ABC" refers to the AER voluntary area-based closure program;
- "ABCA" means the *Business Corporations Act* (Alberta) R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder;
- "AER" means Alberta Energy Regulator, an Alberta corporation responsible for regulating the development of energy resources in the province;
- "AIF" means this annual information form;
- "Alberta Methane Regulations" means the Methane Emission Reduction Regulation enacted by the Government of Alberta lower annual methane emissions by 45% by 2025;
- "Anegada" means Anegada Oil Corp., as acquired by the Company on June 1, 2022;
- "Audit Committee" means the standing committee established by the Board of Directors;
- "BC EAO" refers to the British Columbia's Environmental Assessment Office;
- "Bill C-15" refers to the federal government's Bill C-15: An Act respecting the United Nations Declaration on the Rights of Indigenous Peoples Act;
- "Bill C-69" means Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*, issued by the Canadian federal government;
- "Board" or "Board of Directors" means the board of directors of Tamarack;
- "CEA Agency" means Canadian Environmental Assessment Agency;
- "CEAA" means the Canadian Environmental Assessment Act of 2012;
- "CER" means the Canadian Energy Regulator;
- "CERA" means the *Canadian Energy Regulator Act* (Canada), S.C. 2019, c.28;
- "CETA" means the Comprehensive Economic and Trade Agreement, which Canada and the European Union recently agreed to;
- "CFS" means the Federal Government's Clean Fuel Standard;
- "CFS Regulations" means the Clean Fuel Regulations;
- "CLA" means the Climate Leadership Act (Alberta) which came into force January 1, 2017;
- "CLP" means the Alberta Climate Leadership Plan;
- "Closure Regulations" refers to the new Financial Security and Site Closure Regulations;
- "COGE Handbook" means the most recent publication of the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

- **"Common Shares"** means Common Shares in the capital of Tamarack Valley Energy Ltd.;
- **"Company"** or **"Tamarack"** means Tamarack Valley Energy Ltd., a corporation existing under the laws of the Province of Alberta;
- **"Conservation Regulations"** means the Oil and Gas Conservation Regulations from 2012;
- **"COVID-19"** means the novel coronavirus which was declared a global pandemic by the World Health Organization on March 11, 2020;
- **"CO₂e"** means carbon dioxide equivalent;
- **"CPTPP"** means Comprehensive and Progressive Agreement for Trans-Pacific Partnership;
- **"Crestwynd"** means Crestwynd Exploration Ltd., as acquired by the Company on February 15, 2022;
- **"CUKCA"** means the Canada-United Kingdom Trade Continuity Agreement;
- **"CUSMA"** means the Canada United States Mexico Agreement, sometimes referred to as the United States Mexico Canada Agreement or "USMCA";
- **"Deltastream"** means Deltastream Energy Ltd.;
- **"Deltastream Acquisition"** means the acquisition by Tamarack of Deltastream on October 13, 2022, as further described under the heading *"General Development of the Business – Recent Developments – Developments in 2022"*;
- **"Directive 013"** refers to Alberta's Directive 013: Suspension Requirements for Wells;
- **"Directive 060"** means Upstream Petroleum Industry Flaring, Incinerating and Venting;
- **"Enbridge"** means Enbridge Inc.;
- **"EOR"** means enhanced oil recovery; Enhanced oil recovery improves hydrocarbon recovery by injecting fluids into a hydrocarbon reservoir to increase or maintain reservoir pressure, displace hydrocarbons to production wells, or alter reservoir fluids to improve hydrocarbon flow;
- **"ESTMA"** means the federal government's Extractive Sector Transparency Measures Act;
- **"DAP Notes"** means the Deferred Acquisition Payment Notes; issued in connection with the Deltastream Acquisition, as further described under the heading *"General Development of the Business – Recent Developments – Developments in 2022"*;
- **"DRIPA"** means the Declaration on the Rights of Indigenous Peoples Act which became law in British Columbia in November 2019;
- **"F&D"** means finding and development costs;
- **"FD&A"** means finding, development and acquisition costs;
- **"FDC"** means future development costs;
- **"GGPPA"** means the Federal Government's Greenhouse Gas Pollution Pricing Act;
- **"GHG"** means greenhouse gas;
- **"GHG Cap"** means the Regulatory Framework for an Oil and Gas Sector Greenhouse Gas Emissions Cap;
- **"GLJ"** means GLJ Ltd., independent qualified reserves evaluators;
- **"GLJ Report"** means the independent engineering report by GLJ dated February 13, 2024, and evaluating the crude oil, natural gas and NGL reserves of the Company's non-Clearwater assets effective as of December 31, 2023;
- **"GORR"** means gross overriding royalty;
- **"GORR Disposition"** means the sale of a 2% newly created gross overriding royalty on a select portion of the properties acquired in the Clearwater Acquisitions;
- **"HEHE Plan"** means the Healthy Environment and a Healthy Economy Plan;
- **"IA Agency"** means the Impact Assessment Agency of Canada;
- **"IAA"** refers to the Impact Assessment Act;
- **"IFRS"** means IFRS Accounting Standards as issued by the International Accounting Standards Board;
- **"IOGA"** means the Indian Oil and Gas Act;
- **"IWCP"** means the Inactive Well Compliance Program, implemented by the AER;
- **"Line 3 Replacement"** refers to Enbridge's Line 3 Replacement Project from Hardisty, Alberta, to Superior, Wisconsin;
- **"Line 5"** means the Line 5 Tunnel Replacement Project;
- **"LLR Program"** means Licensee Liability Rating Program;
- **"LMSAA"** refers to the Liabilities Management Statutes Amendment Act;
- **"Manual"** means the Corporate Finance Manual for the TSX-V;
- **"McDaniel"** means McDaniel & Associates Consultants Ltd., independent qualified reserves evaluators;
- **"McDaniel Report"** means the independent engineering report by McDaniel dated February 27, 2024 and evaluating the crude oil, natural gas and NGL reserves of the Company's Clearwater assets effective as of December 31, 2023;
- **"McDaniel and GLJ Reports"** means the GLJ Report and the McDaniel Report;
- **"Modernized IOGA"** means the Act to Amend the Indian Oil and Gas Act, amending and modernizing the IOGA;
- **"NAFTA"** means the North American Free Trade Agreement;
- **"NCIB"** means Normal Course Issuer Bid;
- **"NEB"** means National Energy Board, which was replaced with the CER in summer of 2019;
- **"NGL"** means natural gas liquids;
- **"NGTL System"** means the NOVA Gas Transmission Ltd. pipeline network;
- **"NI 51-101"** means National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities*;
- **"NI 51-102"** means National Instrument 51-102 – *Continuous Disclosure Obligations*;
- **"NI 52-110"** means National Instrument 52-110 – *Audit Committees*;
- **"OBPS"** means the Output-Based Pricing System;
- **"OGCA"** means the Oil and Gas Conservation Act;
- **"Oil and Gas Orphan Fund"** refers to Saskatchewan's LLR Program which is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund;
- **"OPEC"** means Organization of the Petroleum Exporting Countries;
- **"Orphan Fund"** means the orphan fund administered by the Orphan Well Association;

- "OTMA" refers to the Oil Tanker Moratorium Act;
- "OWA" refers to Alberta's Orphan Well Association;
- "Part VI Regulation" refers to the *National Energy Board Act Part VI (Oil and Gas) Regulation*;
- "PDP" refers to proved developed producing reserves;
- "Preferred Shares" means preferred shares in the capital of Tamarack Valley Energy Ltd.;
- "PUD" means proved undeveloped reserves;
- "PRSU Plan" means the Performance and Restricted Share Unit Plan that allows the Board of Directors to grant performance awards to officers, employees and consultants of the Company or its subsidiaries;
- "PSU" means Performance Share Units;
- "PUD" means proved undeveloped reserves;
- "RFPP" refers to the Request for Full Project Proposals for Carbon Sequestration Hubs announced on December 2, 2021;
- "RSU" means Restricted Share Units;
- "SCC" means the Supreme Court of Canada;
- "SEDAR+" means the System for Electronic Document Analysis and Retrieval;
- "SKOGCA" means the Oil and Gas Conservation Act administered by the Saskatchewan Ministry of Energy and Resources;
- "SK LLR Program" refers to Saskatchewan's Liability Rating Program;
- "SLB Framework" means Tamarack's Sustainability-Linked Bond Framework;
- "Senior unsecured notes" means the 7.25% senior unsecured sustainability-linked lending facility notes due May 10, 2027 issued by the Company in accordance with the SLB Framework on February 10, 2022 and September 22, 2022;
- "Credit Facility" means the credit facilities of the Company with a syndicate of Canadian chartered banks, consisting of a three-year covenant-based sustainability-linked lending facility;
- "Sovereignty Act" means the Alberta Sovereignty Within a United Canada Act;
- "SSN" means the Stk'emlupsemc Te Secwepemc Nation;
- "Standards" means the output-based standards;
- "Statement" means the statement of reserves prepared by McDaniel and GLJ;
- "Tamarack" or "Company" means Tamarack Valley Energy Ltd., a corporation existing under the laws of the Province of Alberta;
- "TIER" means Alberta's Technology Innovation and Emissions Reduction regulation;
- "TP" means total proved reserves;
- "TPP" means total proved and probable reserves;
- "TSX" means the Toronto Stock Exchange;
- "TSX-V" means the TSX Venture Exchange;
- "TVE" is the trading symbol of the Company on the TSX;
- "United States" or "U.S." means the United States of America and includes its territories and possessions;
- "UNDRIP" means the United Nations Declaration of the Rights of Indigenous Peoples;
- "UNFCCC" means the United Nations Framework Convention on Climate Change;
- "USMCA" means the United States Mexico Canada Agreement; and
- "WCSB" means the Western Canadian Sedimentary Basin.

RESERVE DEFINITIONS

Categories of Proved, Probable and Possible Reserves have been established to reflect the level of uncertainty associated with the reserve estimates and to provide an indication of the probability of recovery. The classification of reserves requires professional judgment geological knowledge and engineering expertise. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. In the tables set forth under the heading "*Statement of Reserves Data and Other Oil and Gas Information*" and elsewhere in this AIF the following definitions and notes are applicable:

- "**Developed Producing**" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
- "**Developed Non-Producing**" reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- "**Probable**" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable reserves.
- "**Proved**" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved reserves.
- "**Reserves**" or "reserves" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.
- "**Undeveloped**" reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the

estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest-level sum of individual entity estimates for which reserve estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- (a) at least a 90% probability that the quantities recovered will equal or exceed the estimated proved reserves;
- (b) at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- (c) at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods. Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

- **"Development costs"** means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:
 - (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
 - (b) drill, complete and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;
 - (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
 - (d) provide improved recovery systems.
- **"Development well"** means a well drilled inside the established limits of an oil or natural gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
- **"Exploration costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
 - (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");
 - (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease record;
 - (c) dry hole contributions and bottom hole contributions;
 - (d) costs of drilling, completing and equipping exploratory wells; and
 - (e) costs of drilling exploratory type stratigraphic test wells.
- **"Exploratory well"** means a well that is not a development well, a service well or a stratigraphic test well.
- **"Future net revenue"** means a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs and abandonment and reclamation costs.
- **"Gross"** means:
 - (a) in relation to the Company's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;
 - (b) in relation to wells, the total number of wells in which the Company has an interest; and
 - (c) in relation to properties, the total area of properties in which the Company has an interest.
- **"Net"** means:
 - (a) in relation to the Company's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;
 - (b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and
 - (c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.
- **"Service well"** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, saltwater disposal, water supply for injection, observation, or injection for combustion.
- **"Abandonment and reclamation costs"** represent all costs associated with the process of restoring a company's well sites with booked reserves which have been disturbed by oil and gas activities, existing and to be incurred, to a standard imposed by applicable government or regulatory authorities.

CONVENTIONS

Certain other terms used but not defined in this AIF are defined in NI 51-101 and, unless the context otherwise requires, have the same meanings as ascribed to them in NI 51-101. Unless otherwise indicated, references in this AIF to “\$” or “dollars” are to Canadian dollars. All financial information with respect to the Company has been presented in Canadian dollars. Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders.

This AIF contains certain oil and natural gas metrics, including finding and development costs, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company’s performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon.

SELECTED ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	Barrels	Mcf	thousand cubic feet
Mbbl	thousand barrels	Mmcf	million cubic feet
Mmbbl	million barrels	Mcf/d	thousand cubic feet per day
Mstb	1,000 stock tank barrels	Mmcf/d	million cubic feet per day
Bbl/d	barrels per day	MMbtu	million British Thermal Units
BOPD	barrels of oil per day	Bcf	billion cubic feet
NGL	natural gas liquids	GJ	Gigajoule
STB	stock tank barrels	MM or Mm	Million
Other			
AECO	Alberta Energy Company benchmark for natural gas		
API	American Petroleum Institute		
API°	an indication of the specific gravity of crude oil measured on the API gravity scale		
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)		
BOE/d	barrel of oil equivalent per day		
L	Litre		
m³	cubic metres		
Mcfe	means 1,000 cubic feet equivalent on the basis of one Bbl of crude oil for six Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)		
MBOE	1,000 barrels of oil equivalent		
MMBOE	Million barrels of oil equivalent		
\$000s	thousands of dollars		
M\$	thousands of dollars		
Mm\$	millions of dollars		
USD	United States dollars		
WTI	West Texas Intermediate, reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade		

Disclosure provided in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

SELECTED CONVERSIONS

Conversion from	Conversion to	Multiply By
Mcf	cubic meters	28.320
cubic meters	cubic feet	35.315
Bbl	cubic meters	0.159
cubic meters	Bbl	6.290
Feet	Metres	0.305
Meters	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

FORWARD-LOOKING STATEMENTS

Certain statements contained in this AIF constitute forward-looking statements. These statements relate to future events or the Company's future plans or performance. All statements other than statements of historical fact are forward-looking statements. Forward-looking statements or information is often, but not always, identified by the use of words such as "anticipate", "budget", "continue", "evaluate", "monitor", "can", "able", "potential", "consider", "believe", "could", "estimate", "expect", "forecast", "guidance", "intend", "may", "plan", "predict", "project", "should", "focus", "target", "will", or similar words suggesting future outcomes or language suggesting an outlook. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company's presentation of forward-looking information is based on internally generated budgets relating to drilling plans and related costs, expected results from drilling as well as estimated royalties, operating costs and administrative expenses. Tamarack bases the commodity pricing for budget purposes on a range of publicly available pricing forecasts and also considers general economic conditions. Management believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct. Such forward-looking statements should not be unduly relied upon.

In particular, this AIF contains forward-looking statements pertaining to the following:

- business strategy, objectives, strength and focus;
- the performance characteristics of the Company's oil and natural gas properties;
- political, regulatory and international trade uncertainty, the Company's and governmental authorities' current and planned responses thereto and the impact thereof on, without limitation, the Company in particular and the oil and gas industry in general;
- environmental, health, safety and social policies and plans;
- oil and natural gas production levels;
- expectations regarding the Company's growth and risk profile;
- the size of the Company's oil and natural gas reserves;
- projections of market prices and costs, including increased production and capital costs due to inflationary pressures;
- supply of, and demand for, oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- expectations regarding funding of the Company's growth capital expenditures;
- the ability of the Company to achieve drilling success consistent with management's expectations;
- drilling plans, expectations and timing of drilling;
- the Company's obligations under take-or-pay commitments and other arrangements;
- the Company's ability to attract and retain qualified personnel;
- expected levels of royalty rates, production costs, general and administrative costs, costs of services and other costs and expenses;
- future PSU and RSU settlements;
- treatment under governmental regulatory regimes and tax laws;
- expected effect of regulatory regimes and controls;
- tax horizon and future income taxes;
- use of Credit Facility funds and maturity of the Credit Facility;
- the Company's capital program and guidance for 2025 and factors thereunder, including without limitation, expected free funds flow, capital expenditures, borrowings and debt repayments, changes in working capital requirements, and other factors;
- expected source of funds in connection with the Company's capital program;
- expectations regarding commodity prices in 2025;
- deployment of the Company's 2025 capital program;
- future dividend payments;
- share repurchases under the Company's normal course issuer bid;
- the expected allocation of the Company's 2025 capital expenditure budget;
- the source of funds for the Company's 2025 expenditure budget;
- capital expenditure programs and the timing and method of financing thereof; and
- abandonment and reclamation costs, including the Company's estimated asset retirement obligations.

Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. See "*Statement of Reserves Data and Other Oil and Gas Information*".

The forward-looking information and statements contained in this AIF reflect management's current views and are based on certain assumptions, including assumptions as to future economic conditions and courses of action, as well as other factors that management believes are appropriate in the circumstances. Such forward-looking statements are subject to risks and uncertainties and no assurance can be made that any of the events anticipated by such statements will occur or, if they do occur, what benefit the Company will derive from them. The Company has made assumptions regarding, among other things:

- the ability of the Company to achieve drilling success consistent with management's expectations;
- the realization of anticipated benefits of acquisitions and the related drilling programs;
- the ability of the Company to secure equipment, services, supplies and personnel in a timely manner and at an acceptable cost to carry out its activities;
- the timing and cost of pipeline and facility construction and expansion and the ability of the Company to secure adequate product transportation;
- the timely receipt of required regulatory approvals;
- the ability of the Company to market its oil and natural gas and to transport its oil and natural gas to market;

- the ability of the Company to obtain capital to finance its exploration, development and operations; and
- future oil and natural gas prices and demand;
- future exchange rates, interest and inflation rates; and
- that government regulations, laws and tariffs will not change materially.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this AIF:

- volatility in market prices for oil and natural gas, price differentials and the actual prices received for the Company's products;
- ability to pay dividends;
- lack of transportation and inability to produce oil and natural gas reserves and resources;
- adverse regulatory rulings, orders and decisions;
- the impact of U.S. legislative and regulatory policies;
- imposition of tariffs and increased tariffs on Canadian goods by the U.S. administration, including crude oil and natural gas, and that such tariffs (and/or the Canadian government's response to such tariffs) adversely affect the demand and/or market price for the Company's product and /or otherwise adversely affect the Company;
- liabilities inherent in oil and gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- the timing of crude oil and natural gas projects, including the timing of the Canadian LNG projects;
- geological, technical, drilling and processing problems and other problems in producing reserves and resources;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- incorrect assessments of the value of acquisitions and exploration and development programs;
- stock market volatility and market valuations;
- the impact of climate change regulations;
- the impact of changing environmental laws and regulations as well as regulations regarding Indigenous consultation and the resulting effects on the industry in general;
- possible renegotiation and replacement of international trade agreements;
- political uncertainty and geopolitical conflicts;
- the risks of the oil and natural gas industry both domestically and internationally, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand;
- the failure to obtain industry partner and other third-party consents and approvals, as and when required;
- the lack of available capital on acceptable terms;
- third party inability to manage inflationary cost pressures;
- currency fluctuations;
- actions by governmental or regulatory authorities including changes in income tax laws or changes in tax laws and incentive programs relating to the oil and natural gas industry;
- changes in income tax laws or changes in tax laws or trade laws and incentive programs relating to the oil and natural gas industry;
- the effect of litigation proceedings outlined above on the Company's business; and
- the other factors discussed under "Risk Factors".

These factors should not be considered as exhaustive. The reader is cautioned that these factors and risks are difficult to predict and that the assumptions used in the preparation of such information, although considered reasonably accurate at the time of preparation, may prove to be incorrect. Accordingly, readers are cautioned that the actual results achieved will vary from the information provided herein and the variations may be material. Readers are also cautioned that the foregoing list of factors is not exhaustive. Consequently, there are no representations by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking information. Furthermore, the forward-looking statements contained in this AIF are made as of the date hereof, and the Company undertakes no obligation, except as required by applicable securities legislation, to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

SPECIFIED FINANCIAL MEASURES

This document contains various specified financial measures including non-GAAP measures, non-GAAP ratios and capital management measures as further described herein. The Company uses these measures to help evaluate its performance; however, these measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers. The Company uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. The Company uses net debt (working capital deficiency plus debt plus government loan) as an alternative measure of outstanding debt. The Company considers operating field netback a key measure as it demonstrates corporate profitability relative to current commodity prices. Netbacks, which have no IFRS equivalent, are calculated on a per boe basis by deducting royalties, net production and transportation expenses and carbon taxes from petroleum and natural gas sales.

(a) Adjusted Funds Flow (Capital Management Measure) - Tamarack's method of calculating adjusted funds flow may differ from other companies, and therefore may not be comparable to measures used by other companies. Adjusted funds flow is calculated by taking cash-flow from operating activities excluding asset retirement obligation expenditures, transaction costs and changes in non-cash working capital. Both asset retirement obligation expenditures and transaction costs from business combinations both result from the Company's capital budgeting and strategic planning processes which first considers available adjusted funds flow. Asset retirement obligation expenditures may vary from

period to period depending on capital programs, government regulations and the maturity of the Company's operating areas. By excluding changes in non-cash working capital from cash provided by operating activities, the 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 can also be calculated on a per boe basis. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares used in calculating income (loss) per share. The calculation of the Company's adjusted funds flow can be seen in the Company's 2023 Management's Discussion and Analysis in the section titled "Adjusted funds flow and Net Income".

(b) **Free Funds Flow (Non-GAAP Measure)** – Tamarack's method of calculating free funds flow may differ from other companies, and therefore may not be comparable to measures used by other companies. Free funds flow is calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions. Management believes that free funds flow provides a useful measure to determine Tamarack's ability to improve returns and to manage the long-term value of the business.

(c) **Net Production Expenses and Operating Field Netback (Non-GAAP Measures)** - Management uses certain industry benchmarks, such as operating field netback, to analyze financial and operating performance. This benchmark does not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Net production expenses are determined by deducting processing income primarily generated by processing third party volumes at processing facilities where the Company has an ownership interest. Operating field netback equals total petroleum and natural gas sales, less royalties, net production and transportation expenses and carbon tax. These metrics can also be calculated on a per boe basis. Management considers operating field netback an important measure to evaluate its operational performance, as it demonstrates field level profitability relative to current commodity prices (on a boe basis, this is a non-IFRS ratio). The calculation of the Company's operating field netbacks can be seen in the Company's 2023 Management's Discussion and Analysis in the section titled "Operating Netback".

(d) **Net Debt and Working Capital Deficiency (Surplus) (Capital Management Measure)** - Tamarack closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. Net debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. The Company uses net debt and working capital deficiency (surplus) to assess liquidity and balance sheet strength by aggregating the select financial statement assets and financial liabilities on the Company's balance sheet. The calculation of the Company's Net Debt and Working Capital Deficiency (Surplus) can be seen in the Company's 2023 Management's Discussion and Analysis in the section titled "Liquidity and Capital Resources".

(e) **Net Debt to Annualized Adjusted Funds Flow (Capital Management Measure)** – Management uses certain industry benchmarks, such as net debt to annualized adjusted funds flow, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. This benchmark is calculated as estimated net debt at a point in time divided by the estimated adjusted funds flow for the most recently completed quarter. Management considers net debt to annualized adjusted funds flow as a key measure as it provides a snapshot of the overall financial health of a company and its ability to pay off its debt and take on new debt, if necessary.

APPENDIX "A"

Form 51-101F2

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS OR AUDITORS

To the board of directors of Tamarack Valley Energy Ltd. (the "Company"):

- We have evaluated the Company's reserves data as at December 31, 2024. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2024, estimated using forecast prices and costs.
- The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
- We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).
- Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
- The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2024, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Valuation	Location of Reserves (Country)	NPV10 Audited (\$000)	NPV10 Evaluated (\$000)	NPV10 Reviewed (\$000)	NPV10 Total (\$000)
McDaniel & Associates Consultants Ltd.	Dec 31/24	Canada	-	3,405,148	-	3,405,148
GLJ Ltd.	Dec 31/24	Canada	-	1,736,517	-	1,736,517
		-		5,141,665	-	5,141,665

6. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.
8. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. EXECUTED as to our report referred to above:

GLJ Ltd.

Calgary, Alberta, Canada, January 8, 2025

“Originally Signed by”

Jonathan B. Hagel, P. Eng.
Vice President, Corporate Evaluations

McDaniel & Associates Consultants Ltd.

Calgary, Alberta Canada, January 20, 2025

“Originally Signed by”

Michael J. Verney, P. Eng.
Executive Vice President

APPENDIX “B”

FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Tamarack Valley Energy Ltd. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data.

McDaniel & Associates Consultants Ltd. and GLJ Ltd., each an independent qualified reserves evaluator, has evaluated and reviewed the Company's reserves data. The reports of the independent qualified reserves evaluators are presented below.

The Reserves Committee of the board of directors of the Company has

- (a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;
- (b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation and, in the event of a proposal to change the independent qualified reserves evaluators, to inquire whether there had been disputes between the previous independent qualified reserves evaluators and management; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and natural gas information;
- (b) the filing of Form 51-101F2 which is the reports of the independent qualified reserves evaluators on the reserves data; and
- (c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) *“Brian L. Schmidt”*

Brian L. Schmidt, President & CEO

(signed) *“Robert Spitzer”*

Robert Spitzer, Director

(signed) *“Ben Stoodley”*

Ben Stoodley, Vice President, Engineering

(signed) *“John Leach”*

John Leach, Director

(signed) *“Caralyn Bennett”*

Caralyn Bennett, Director

February 11, 2025

APPENDIX “C”

AUDIT COMMITTEE MANDATE

Policy Statement

Tamarack Valley Energy Ltd. (the “Corporation”) has established and maintains an Audit Committee, (the “Committee”) to assist the Board of Directors (the “Board”) in carrying out its oversight responsibility with respect to public reporting related to the Corporation's internal controls, financial reporting and risk management processes. The Committee will be provided with resources commensurate with the duties and responsibilities set out herein and assigned to it by the Board from time to time, including administrative support. If determined necessary by the

Committee, it will have the discretion to institute investigations of improprieties, or suspected improprieties within the scope of its responsibilities, including the standing authority to retain special counsel or experts.

Composition

1. The Committee shall consist of at least three directors. The Board shall appoint the members of the Committee. The Board shall appoint one member of the Committee to be the chairman of the Committee (the “**Chairman**”).
2. Each director appointed to the committee by the Board shall be “independent” as required under the applicable securities laws and the applicable rules of any stock exchange on which the securities of the Corporation are listed unless a member is deemed not to be independent only by virtue of being an executive officer of a subsidiary entity.
3. Each member of the Committee shall be “financially literate” as required under the applicable securities laws, including without limitation National Instrument 52-110 - Audit Committees (“**NI 52-110**”). In order to be financially literate, a director must have the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation’s financial statements. If available, at least one member shall have “accounting or related financial management expertise”, meaning the ability to analyze and interpret a full set of financial statements, including the notes attached thereto, in accordance with Canadian generally accepted accounting principles.
4. A director appointed by the Board to the Committee shall be a member of the Committee until replaced by the Board or until his or her resignation.

Meetings and Operations

1. The Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chairman and whenever a meeting is requested by the Board, a member of the Committee, the external auditors (the “**auditors**”), or an officer of the Corporation. Meetings of the Committee shall correspond with the review of the quarterly and annual financial statements and the associated management’s discussion and analysis (“**MD&A**”).
2. Notice of each meeting of the Committee shall be given to each member of the Committee and to the auditors, who shall be entitled to attend each meeting of the Committee and who shall attend whenever requested to do so by a member of the Committee.
3. A quorum for the transaction of business at a meeting of the Committee shall consist of two members of the Committee.
4. A member or members of the Committee may participate in a meeting of the Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.
5. In the absence of the Chairman, the members of the Committee shall choose one of the members present to be chairman of the meeting. In addition, the members of the Committee shall choose one of the persons present to be the secretary of the meeting.
6. The President and Chief Executive Officer and the Vice President, Finance and Chief Financial Officer and other members of senior management shall be invited to attend meetings of the Committee upon the request of the Committee; subject, however, to the requirement that the Committee (i) hold in camera sessions of the members of the Committee, without management representatives present at every meeting of the Committee, and (ii) meet with the auditors separately and independent of management at every meeting at which the auditors are in attendance.
7. Minutes shall be kept of all meetings of the Committee.

Authority and Reporting

1. In discharging its duties and responsibilities, the Committee shall have the authority to:
 - (a) inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates;
 - (b) discuss with the management of the Corporation, its subsidiaries and affiliates and staff of the Corporation, any affected party, contractors and consultants of the Corporation and the auditors, such accounts, records and other matters as any member of the Committee considers necessary and appropriate;
 - (c) engage independent counsel and other advisors (including a second firm of external auditors) as it determines necessary to carry out its duties; and
 - (d) set and pay the compensation for any advisors employed by the Committee.
2. The Committee shall after each meeting, report to the Board the results of its activities and any reviews undertaken and make recommendations to the Board as deemed appropriate.

Primary Duties and Responsibilities

1. The Committee’s primary duties and responsibilities regarding its audit function are to:
 - (a) review with the external auditors the audit function generally, the objectives, staffing, locations, co-ordination, and scope of proposed audits of the financial statements of the Corporation;
 - (b) review with management and the external auditors, and recommend to the Board for approval and release to shareholders, the quarterly and annual financial statements of the Corporation, together with related reports to shareholders, MD&A associated with such financial statements and, delegated by the board, other public filings (such as prospectus or annual information forms) containing financial disclosures;
 - (c) review with the auditors and management, and monitor the management of, the principal risks that could affect the financial reporting of the Corporation;
 - (d) review and assess the framework of and periodically consider the integrity of the Corporation’s financial reporting process and system of internal controls regarding financial reporting and accounting compliance through discussions with management and the auditor;
 - (e) consider the independence and performance of the Corporation’s auditors;
 - (f) deal directly with the auditors to approve the annual external audit plan, other services (if any) and associated fees;
 - (g) approve the audit engagement and consider the external audit process and results;

- (h) provide an avenue of communication among the auditors (both external and internal, if any), management and the Board, and direct the external auditors to report directly to the Committee; and
 - (i) establish and monitor procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters and the anonymous submission by employees of concerns regarding questionable accounting or auditing matters or other “whistleblower” issues, and review the minutes of any Committee meetings held in connection with any subsidiary companies of the Corporation.
2. The Committee shall, in connection with the financial aspects of the Corporation’s business:
- (a) review the annual external audit plan with the Corporation’s auditors and with management and approve the engagement letter relating thereto;
 - (b) discuss with management and the auditors any proposed changes in major accounting policies or principles, the presentation and effect of significant risks and uncertainties and key estimates and judgements of management that may be material to financial reporting;
 - (c) review with management and with the auditors significant financial reporting issues arising during the most recent fiscal period and the resolution or proposed resolution of such issues;
 - (d) review any problems experienced or concerns expressed by the auditors in performing an audit, including any restrictions imposed by management or significant accounting issues on which there was a disagreement with management;
 - (e) review with management the process of identifying, monitoring and reporting the Corporation’s risk management policies and procedures and the principal risks affecting financial reporting;
 - (f) review and evaluate any recommendations of the auditors and decide the appropriate course of action;
 - (g) consider consistency of the data reported in the financial statements, annual and quarterly reports and related public disclosure documents;
 - (h) review audited annual financial statements and related documents in conjunction with the report of the auditors and significant variances between comparative reporting periods as set out in the MD&A;
 - (i) review, independently of management, and without management present, the results of the annual external audit, the audit report thereon and the auditor’s review of the related MD&A, and discuss with the auditor the quality of accounting principles used, any alternative treatments of financial information that have been discussed with management, the ramifications of their use and the auditor’s preferred treatment and any other material communication with management;
 - (j) consider and review with management:
 - (i) all unadjusted errors identified by the external auditors,
 - (ii) the internal control memorandum or management letter containing the recommendations of the auditors and management’s response, if any, including any evaluation of the adequacy and effectiveness of the internal financial controls of the Corporation and subsequent follow-up to any identified weakness;
 - (k) review with management and the auditors the quarterly unaudited financial statements and MD&A before release to the public;
 - (l) before release, review and if appropriate, recommend for approval by the Board, all public disclosure documents containing audited or unaudited financial information, including any prospectus, annual reports, annual information forms, MD&A and press releases;
 - (m) review and approve the Corporation’s hiring policies regarding employees and former employees of the present and former auditors;
 - (n) review with management the Corporation’s relationship with regulators and the timelines and accuracy of the Corporation’s filings with regulatory agencies; and
 - (o) review with management all related party transactions and the development of policies and procedures related to those transactions.

Auditors

1. The Committee shall:
- (a) consider the independence and performance of the auditors and annually recommend to the Board the appointment or discharge of the auditor when circumstances are warranted and recommend to the Board the compensation of the auditors;
 - (b) pre-approve all non-audit services to be provided to the Corporation or its subsidiary entities by the auditors, or the auditors of any of the Corporation’s subsidiary entities;
 - (c) when there is to be a change of auditors, review all issues and provide documentation related to the change, including the information to be included in the Notice of Change of Auditors and related documentation required pursuant to National Instrument 51-102 - Continuous Disclosure Obligations, with respect to a change of auditors (or any successor legislation) and the planned steps for an orderly transition period;
 - (d) review all material written communications between the auditor and management; and
 - (e) review all reportable events, including disagreements, unresolved issues and consultations, as defined by applicable securities policies, on a routine basis, whether or not there is to be a change of auditors.

Financing Matters

1. The Committee shall:
- (a) review all securities offering documents (including documents incorporated therein by reference) of the Corporation;
 - (b) review findings, if any, from examinations or reviews performed by regulatory agencies with respect to financial matters;
 - (c) review management’s consideration of the Corporation’s compliance with laws and regulations;
 - (d) review management’s assessment of current and expected future compliance with covenants under any financing agreements;
 - (e) if requested by the Board, review the proposed issuance of debt and equity instruments including public and private debt, equity and hybrid securities, credit facilities with banks and others, and other credit arrangements such as material capital and operating leases, as well as any related securities filings;
 - (f) if requested by the Board, review the proposed repurchase of public and private debt, equity and hybrid securities; and

- (g) in consultation with management understand the Corporation's capital structure and financial risks arising from exposure to such things as commodity prices, interest rates, foreign currency exchange rates and credit and review the management of these risks including any proposed hedging of the exposures, including receiving a summary report of the hedging activities and hedge-related instruments.

Other

1. The Committee shall consider the amount and terms of any insurance to be obtained or maintained by the Corporation with respect to risks inherent in its operations and potential liabilities incurred by the directors or officers in the discharge of their duties and responsibilities.
2. The Committee shall consider the appointments of the Chief Financial Officer and any key financial managers who are involved in the financial reporting process.
3. The Committee shall enquire into and determine the appropriate resolution of any conflict of interest in respect of audit or financial matters, which are directed to the Committee by any member of the Board, a shareholder of the Corporation, the auditors, or management.
4. The Committee shall review, on an annual basis this mandate and recommend any changes to the Board.
5. The Committee will perform any other activities consistent with this mandate, the Corporation's bylaws and applicable laws as the Committee or the Board deems necessary or appropriate.

Scope and Reliance

1. While the Committee has the responsibilities, duties and authorities herein, it is not required to plan or conduct audits or to determine that the Corporation's financial statements and disclosures are complete and accurate or are in accordance with generally accepted accounting principles and applicable rules and regulations. These are the responsibilities of management and the auditors. The Committee, its Chairman and any of its members who have accounting or related financial management experience or expertise, are members of the Board, appointed to the Committee to provide broad oversight to the financial disclosure, financial risk and control related activities of the Corporation, and are specifically not accountable nor responsible for the day-to-day operation of such activities. Although designation of a member or members as being "financially literate" or a "financial expert" is based on each such individual's education and experience, which that individual will bring to bear in carrying out his or her duties on the Committee, designation as being "financially literate" or a "financial expert" does not impose on such person any duties, obligations or liability that are greater than the duties, obligations and liability imposed on such person as a member of the Committee and Board in the absence of such designation. Rather, the role of any financially literate individual or financial expert, like the role of all Committee members, is to oversee the process and not to certify or guarantee the internal or external audit of the Corporation's; financial information or public disclosure.
2. Absent actual knowledge to the contrary (which shall be promptly reported to the Board), each member of the Committee shall be entitled to rely on (i) the integrity of those persons or organizations within and outside the Corporation from which it receives information, (ii) the accuracy of the information provided to the Committee by such persons or organizations, and (iii) representations made by management of the Corporation, the external auditors of the Corporation, independent counsel, and other advisors and experts to the Corporation and its subsidiaries.

Pre-Approval Policies and Procedures

1. The Audit Committee has established a pre-approval policy and procedures for the engagement of non-audit services. The Audit Committee must approve all engagements for non-audit services which are expected to exceed \$50,000 per engagement before the engagement may commence. For engagements for non-audit services which are expected to be less than \$50,000 the engagement may commence upon approval by the Chairman of the Audit Committee with all members being informed of the service at the next meeting of the Committee. All recommendations for services will be submitted by the Vice-President, Finance and Chief Financial Officer.