



MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the three months ended March 31, 2023 and 2022. This MD&A is dated and based on information available as at May 10, 2023 and should be read in conjunction with the unaudited condensed consolidated interim financial statements ("financial statements") and the notes thereto for the three months ended March 31, 2023 and 2022 and the audited consolidated financial statements for the year ended December 31, 2022. Additional information relating to Tamarack, including Tamarack's Annual Information Form for the year ended December 31, 2022, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

The financial statements have been prepared in accordance with International Accounting Standards 34 "Interim Financial Reporting". The Company uses certain Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures in this MD&A. Certain financial measures are also presented on a per bbl, per boe, per mcf or per share basis that results in those measures considered as Supplemental Financial Measures. For a discussion of those measures, including the method of calculation, please refer to the section titled "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures" beginning on page 21. Unless otherwise indicated, all references to dollar amounts are in Canadian ("CAD") currency.

First Quarter in Review

In the first quarter of 2023, global crude oil prices continued to soften due to macroeconomic slowdown concerns weighing on the global demand outlook. Global supply remained resilient as Russian exports continued to be strong, easing concerns over supply disruption and as a result of the unprecedented release of US government strategic petroleum reserves ("SPRs") through 2022. On April 2, 2023, OPEC+ announced a cut to the group's production quotas which has been supportive to pricing.

Specific to Canadian oil pricing, the Western Canadian Select ("WCS") differential widened significantly versus the first quarter of 2022 as unplanned refinery outages and Keystone pipeline apportionment resulted in demand and supply disruption. Although volatility is likely to persist, management's outlook, specifically with respect to WCS pricing, remains constructive as heavy and sour crude SPR sales have been completed and as additional refinery capacity additions are set to be brought on-line through the back half of 2023 creating additional competition for WCS barrels in the Gulf Coast. Longer term, the TMX pipeline expansion, which is expected to be complete and on-line in the first quarter of 2024, will provide additional egress optionality for WCS barrels.

Q1 marked the first full quarter of having the Deltastream assets under Tamarack's control with operational and capital synergies beginning to be realized as the Company executes its larger Clearwater development program. The assets continue to deliver at or above our forecast at the time of the acquisition with additional upside and potential capital efficiency improvements being identified.

Corporately, production averaged 67,938 boe/d for the first quarter, representing a 64% year over year increase. Despite an active and successful first quarter drilling program, production fell at the low end of guidance primarily owing to unplanned maintenance on a TC Energy pipeline outage. In total, third party downtime impacted the quarter by approximately 1,000 boe/d. Adjusted funds flow of \$157.3 million in the first quarter was down \$9.3 million year over year primarily due to declining commodity prices and a wider WCS differential. Looking ahead, the narrowing of the WCS differentials along with the minimum apportionment, management expects realized pricing to improve in the second quarter and the back half of the year.

The Company invested \$148.2 million in exploration, development and facility expenditures which resulted in free funds flow, excluding acquisition expenditures, of \$9.1 million. The Company's major infrastructure projects remain on-time and on budget. The Wembley gas plant in the Charlie Lake light oil play is expected to be on-stream by the end of the second quarter and is expected to reduce operating costs and provide a greater level of control over the processing of the Company's sweet gas volumes associated with the Charlie Lake oil development. The Clearwater Nipisi Pipeline and Terminal project is expected to be on-line in the third quarter of this year and drive both operating cost savings along with netback enhancement from blending. When combining both projects, the Company expects to see operating costs and transport costs driven lower throughout the year.

Subsequent to the quarter, the Company extended its three-year sustainability-linked covenant-based facility ("SLL Facility") to May 2026 and increased it to \$875.0 million from \$700.0 million. The Company also decreased its Term Facility to \$200.0 million.

Annual Guidance

The Company's capital budget range remains unchanged at \$425 million to \$475 million. Management will monitor commodity prices and will remain flexible with its second half capital program. Tamarack continues to target spending at the lower half of the range with a focus on maximizing free funds flow for debt repayment and enhancing shareholder returns as debt thresholds are met. Our 2023 capital guidance balances maximizing free funds flow generation over both the short and long term; with a significant amount of 2023 capital being directed towards both waterflood and infrastructure initiatives to set up lower sustaining capital and operating cost requirements throughout our five-year plan.

Subsequent to the first quarter, Tamarack disposed of certain non-core natural gas assets and decommissioning obligations for approximately \$2.3 million in gross proceeds consisting of 400 boe/d of production. This disposition along with the unplanned first quarter downtime will see our 2023 production guidance range updated to 67,000 to 71,000 boe/d. Our operating cost, transportation expense, royalty, G&A and interest guidance range remain unchanged.

Tamarack's 2023 updated annual guidance is summarized below:

	Original Guidance for the year ended December 31,	Updated Guidance for the year ended December 31,
	2023	2023
Capital expenditures (\$mm) ⁽¹⁾	\$425 - \$475	\$425 - \$475
Production		
Light oil (bbls/d)	16,500 - 17,500	16,500 - 17,500
Heavy oil (bbls/d)	35,000 - 37,000	34,750 - 36,500
Natural gas liquids (bbls/d)	3,500 - 4,500	3,500 - 4,500
Natural gas (mcf/d)	73,000 - 78,000	71,000 - 75,000
Annual average production (boe/d)	68,000 - 72,000	67,000 - 71,000
Average oil & NGL weighting	81% - 83%	81% - 83%
Expenses:		
Royalty rate (percent of sales - %)	19% - 21%	19% - 21%
Net production (\$/boe) ⁽²⁾	\$9.00 - \$9.50	\$9.00 - \$9.50
Transportation (\$/boe)	\$3.50 - \$4.00	\$3.50 - \$4.00
General and administrative (\$/boe)	\$1.25 - \$1.35	\$1.25 - \$1.35
Interest (\$/boe)	\$3.80 - \$4.00	\$3.80 - \$4.00
Taxes (\$/boe) ⁽³⁾⁽⁴⁾	\$3.75 - \$4.10	\$3.75 - \$4.10
Leasing expenditures (\$mm)	\$3.5 - \$4.5	\$3.5 - \$4.5

⁽¹⁾ Capital E&D budget includes exploration and development capital, environmental, social and governance ("ESG") initiatives, and facilities but excludes asset acquisitions and dispositions, ARO, land and seismic.

⁽²⁾ Refer to the section "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures".

⁽³⁾ Tax costs per boe are particularly sensitive to changes in commodity pricing and are represented in the guidance under the Company's best outlook of budget and strip pricing but may change significantly under alternate price conditions throughout the year.

⁽⁴⁾ Tax guidance has been updated from percentage of net operating income to cost per boe for the original and updated guidance for the year ended December 31, 2023.

Q1 2023 Operational and Financial Highlights

	Three months ended		
	March 31,		
	2023	2022	% change
(\$ thousands, except per share)			
Total oil, natural gas and processing revenue	379,455	298,895	27
Cash flow from operating activities	59,624	132,853	(55)
Per share – basic	\$ 0.11	\$ 0.32	(66)
Per share – diluted	\$ 0.11	\$ 0.31	(65)
Adjusted funds flow ⁽¹⁾	157,271	166,581	(6)
Per share – basic ⁽³⁾	\$ 0.28	\$ 0.40	(30)
Per share – diluted ⁽³⁾	\$ 0.28	\$ 0.39	(28)
Net income	2,505	26,457	(91)
Per share – basic	–	\$ 0.06	(100)
Per share – diluted	–	\$ 0.06	(100)
Net debt ⁽¹⁾	(1,374,068)	(556,374)	147
Capital expenditures ⁽¹⁾	148,162	125,367	18
Weighted average shares outstanding (thousands)			
Basic	556,548	419,251	33
Diluted	560,503	427,546	31
Share Trading			
High	\$ 4.88	\$ 6.09	(20)
Low	\$ 3.48	\$ 3.90	(11)
Average daily share trading volume (thousands)	3,056	3,769	(19)
Average daily production			
Light oil (bbls/d)	17,035	17,868	(5)
Heavy oil (bbls/d)	34,399	7,522	357
NGL (bbls/d)	4,122	4,113	–
Natural gas (mcf/d)	74,293	70,989	5
Total (boe/d)	67,938	41,335	64
Average sale prices			
Light oil (\$/bbl)	94.97	110.07	(14)
Heavy oil, net of blending expense ⁽²⁾ (\$/bbl)	61.60	94.43	(35)
NGL (\$/bbl)	45.91	56.21	(18)
Natural gas (\$/mcf)	3.50	5.70	(39)
Total (\$/boe)	61.61	80.17	(23)
Operating netback (\$/Boe)			
Average realized sales, net of blending expense ⁽²⁾	61.61	80.17	(23)
Royalty expenses	(11.99)	(15.72)	(24)
Net production and transportation expenses ⁽²⁾	(14.39)	(12.07)	19
Operating field netback (\$/Boe) ⁽²⁾			
Realized commodity hedging loss	(1.06)	(4.00)	(74)
Operating netback (\$/Boe) ⁽²⁾			
	34.17	48.38	(29)
Adjusted funds flow (\$/Boe) ⁽³⁾			
	25.72	44.78	(43)

⁽¹⁾ Capital Management Measure; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

⁽²⁾ Non-IFRS Financial Ratio; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

⁽³⁾ Supplemental Financial Measure; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

Production

	Three months ended March 31,		
	2023	2022	% change
Production			
Light oil (bbls/d)	17,035	17,868	(5)
Heavy oil (bbls/d)	34,399	7,522	357
Natural gas liquids (bbls/d)	4,122	4,113	–
Natural gas (mcf/d)	74,293	70,989	5
Total (boe/d)	67,938	41,335	64
Percentage of oil and NGL	82%	71%	15

Average production for Q1/23 increased 64% compared to the same period in 2022 due to the acquisitions that closed throughout 2022 and the 2022 development program, partially offset by expected declines of existing base production and disposition of non-core Viking oil cash generating unit (“CGU”) assets in Q3/22. The Company’s oil and NGL weighting for the three months ended March 31, 2023 was 82%, a 15% increase as compared to the same period in 2022 due to the acquisitions.

Petroleum and Natural Gas Sales

	Three months ended March 31,		
	2023	2022	% change
Revenue (\$ thousands)			
Light oil	\$145,613	\$177,096	(18)
Heavy oil, net of blending expense ⁽¹⁾	190,693	63,926	198
Natural gas liquids	17,032	20,809	(18)
Natural gas	23,382	36,423	(36)
Total, net of blending expense ⁽¹⁾	\$376,720	\$298,254	26
Average realized price:			
Light oil (\$/bbl)	94.97	110.07	(14)
Heavy oil, net of blending expense (\$/bbl) ⁽²⁾	61.60	94.43	(35)
Natural gas liquids (\$/bbl)	45.91	56.21	(18)
Combined average oil and NGL (\$/boe)	70.67	98.61	(28)
Natural gas (\$/mcf)	3.50	5.70	(39)
Revenue, net of blending expense (\$/boe) ⁽²⁾	61.61	80.17	(23)
Benchmark pricing:			
West Texas Intermediate (US\$/bbl)	76.13	94.38	(19)
Edm Par Differential (US\$/bbl)	2.88	2.98	(3)
WCS differential (US\$/bbl)	24.88	14.60	70
Edmonton Par (Cdn\$/bbl)	99.01	115.73	(14)
Hardisty Heavy (Cdn\$/bbl)	69.30	101.02	(31)
NYMEX monthly settlement (US\$/mmbtu)	3.42	4.91	(30)
AECO daily index (Cdn\$/mcf)	3.20	4.71	(32)
AECO monthly index (Cdn\$/mcf)	4.32	4.59	(6)

⁽¹⁾ Non-IFRS Financial Measure; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

⁽²⁾ Non-IFRS Financial Ratio; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

Revenue per boe from oil, natural gas and NGL sales, net of blending expense was \$61.61 per boe for Q1 2023 compared to \$80.17 per boe in Q1 2022. The decrease is due to the lower West Texas Intermediate (“WTI”) benchmark price, a wider WCS differential, and lower AECO/NYMEX gas prices year over year.

The Company’s realized light oil price of \$94.97 per bbl for Q1 2023 decreased compared to \$110.07 per bbl in the same period in 2022 primarily on the back of weaker WTI pricing year over year. The Edmonton Par light oil differential improved slightly to an average of US\$2.88 per bbl for Q1 2023 compared to US\$2.98 per bbl in the first quarter of 2022.

The Company’s realized heavy oil price, net of blending expense, averaged \$61.60 per bbl for Q1 2023, a decrease from the realized heavy oil price of \$94.43 per bbl in Q1 2022. The WCS heavy oil differential weakened substantially to an average of US\$24.88 per bbl in Q1 2023 compared to US\$14.60 per bbl in the first quarter of 2022. This was primarily due to the United States SPR withdrawal of heavy oil and US refinery outages. In addition to the weaker benchmark WCS differential, Tamarack’s realized wellhead differential was impacted by the Keystone pipeline apportionment and subsequent adjusted pricing of bbls during the months of January and February 2023. The WCS heavy oil pricing outlook remains constructive for the remainder of 2023, as the SPR heavy oil withdrawals and refinery turnarounds have been completed and wound down, respectively.

The Company’s realized NGL pricing of \$45.91 per bbl in Q1 2023 decreased from \$56.21 per bbl in Q1 2022 largely due to the drop in WTI. The WTI benchmark price decreased to US\$76.13 per bbl for Q1 2023 compared to US\$94.38 per bbl for the same period in 2022. Q1 2022 saw WTI increase on the uncertainty around the Russia-Ukraine conflict. WTI was lower in Q1 2023 due to recession fears.

Tamarack’s realized natural gas price decreased to \$3.50 per mcf in Q1 2023 from \$5.70 per mcf in Q1 2022. The AECO daily benchmark price decreased to \$3.20 per mcf in Q1 2023 from \$4.71 per mcf in Q1 2022; while the NYMEX monthly settlement price decreased to US\$3.42 per mmbtu in Q1 2023 from US\$4.91 per mmbtu in Q1 2022. Both AECO and NYMEX decreased due to the warmer than normal winter in the US which reduced demand and overall supply surplus across the continent. Tamarack’s realized pricing was 39% lower in Q1 2023 compared to the same period in 2022 due to the weather-related pricing impacts in the markets where Tamarack has price exposure.

Risk Management

The Company may use both financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates. All such transactions are conducted within risk management tolerances that are reviewed quarterly by Tamarack's Board of Directors. At March 31, 2023, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the tables below.

West Texas Intermediate and Differential Crude Oil Derivatives:

	Q2 2023		Q3 2023			Q4 2023			
WTI Put									
Volume (bbls/d)	2,000		-			-			
Average Put/Premium (USD/bbl)	55.00	2.90	-	-	-	-	-	-	
WTI 2-way Collar									
Volume (bbls/d)	30,500		24,250			7,500			
Average Put/Call/Premium (USD/bbl)	69.42	103.80	2.84	67.67	98.23	2.96	68.00	90.33	3.00
Volume (bbls/d)	1,050		850			850			
Average Put/Call/Premium (CAD/bbl)	82.90	110.94	-	80.44	108.64	-	80.44	108.64	-
WTI Fixed Price									
Volume (bbls/d)	300		200			200			
Average Fixed Price (CAD/bbl)	94.23		91.75			91.75			
Mixed Sweet Blend Differential (MSW)									
Volume (bbls/d)	5,000		2,000			1,000			
Average Fixed Price (USD/bbl)	(2.92)		(2.80)			(2.70)			
Western Canadian Select Differential (WCS)									
Volume (bbls/d)	12,000		7,000			4,000			
Average Fixed Price (USD/bbl)	(20.48)		(16.11)			(17.94)			
Volume (bbls/d)	1,000		700			700			
Average Fixed Price (CAD/bbl)	(18.66)		(19.29)			(19.29)			

Natural Gas Derivatives:

	Summer 23 ⁽¹⁾	
AECO – NYMEX Basis		
Volume (mmbtu/d)	17,500	
Average Fixed Price (USD/mmbtu)	(1.87)	
NYMEX Collar		
Volume (mmbtu/d)	17,500	
Average Put/Call (USD/mmbtu)	4.56	6.98

⁽¹⁾ Summer runs from April 1 to October 31 of the given year.

Foreign Exchange Derivatives:

	Q2 2023			Q3 2023			Q4 2023			Q1 2024		
CAD/USD Put												
Amount (USD/month)	\$3,000,000			-			-			-		
Average Put/Premium (CAD/USD)	1.3375	0.0100		-	-		-	-		-	-	
CAD/USD Collar												
Amount (USD/month)	\$10,000,000			\$12,000,000			\$12,000,000			-		
Average Put/Call (CAD/USD)	1.3205	1.3888		1.3254	1.3909		1.3254	1.3909		-	-	
CAD/USD Variable Rate Collar												
Amount (USD/month)	\$9,000,000			\$11,500,000			\$11,500,000			\$8,500,000		
Average Put/Call/Knockout Rate (CAD/USD) ⁽¹⁾	1.33	1.42	1.37	1.33	1.41	1.36	1.33	1.41	1.36	1.33	1.41	1.36
CAD/USD Variable Rate Collar (Extendable Option)⁽²⁾												
Amount (USD/month)	\$10,000,000			\$12,500,000			\$12,500,000			\$4,500,000		
Average Put/Call/Knockout Rate (CAD/USD) ⁽¹⁾	1.33	1.40	1.37	1.33	1.40	1.36	1.33	1.40	1.36	1.33	1.41	1.37
CAD/USD Swap												
Amount (USD/month)	\$5,000,000			\$6,000,000			\$6,000,000			\$1,000,000		
Average Fixed Price (CAD/USD)	1.3413			1.3399			1.3399			1.3600		

	Q2 2024			Q3 2024			Q4 2024		
CAD/USD Variable Rate Collar									
Amount (USD/month)	\$8,500,000			\$2,000,000			\$2,000,000		
Average Put/Call/Knockout Rate (CAD/USD)	1.33	1.41	1.36	1.34	1.42	1.36	1.34	1.42	1.36
CAD/USD Variable Rate Collar (Extendable Option)									
Amount (USD/month)	\$4,500,000			\$2,000,000			\$2,000,000		
Average Put/Call/Knockout Rate (CAD/USD)	1.33	1.41	1.37	1.32	1.40	1.38	1.32	1.40	1.38
CAD/USD Swap									
Amount (USD/month)	\$1,000,000			-			-		
Average Fixed Price (CAD/USD)	1.3600			-			-		

⁽¹⁾ If the average rate for the month exceeds the call, Tamarack receives an average rate forward equivalent to the knockout rate.

⁽²⁾ Includes an extension option at the end of the collar, at the counterparty's option, for an equivalent term at an average rate forward fixed price equal to the call. If all extension options were exercised, Tamarack would hold additional average rate forward contracts as follows: H1/24 - \$10 million at 1.3975; H2/24 - \$15.0 million at 1.4017; H1/25 - \$2.0 million at 1.4000; H2/25 - \$2.0 million at 1.4000.

Interest Rate Derivatives:

	2023	2024
CDOR Swap		
Amount (million CAD/year)	34.3	6.4
Average Interest Rate	1.191%	1.043%

At March 31, 2023, the derivative commodity, foreign exchange and interest rate contracts were fair valued with a net liability value of \$12.7 million (December 31, 2022 – \$10.3 million net liability) recorded on the balance sheet. The Company recorded an unrealized loss of \$2.3 million and a realized loss of \$6.5 million in earnings for the three months ended March 31, 2023, compared to an unrealized loss of \$56.6 million and a realized loss of \$14.9 million during the same period in 2022. The Company manages credit risk for these contracts by engaging with a variety of counterparties, all of which are investment-grade banking institutions or large purchasers of commodities. All counterparties have been assessed for credit worthiness.

Subsequent to March 31, 2023, the Company has entered into the financial contracts noted in the table below.

West Texas Intermediate and Differential Crude Oil Derivatives:

	Q3 2023			Q4 2023			Q1 2024			Q2 2024		
WTI 2-way Collar												
Volume (bbls/d)	-			2,000			-			-		
Average Put/Call/Premium (USD/bbl)	-	-	-	67.00	95.35	2.00	-	-	-	-	-	-
Western Canadian Select Differential (WCS)												
Volume (bbls/d)	6,000			3,500			1,000			1,500		
Average Fixed Price (USD/bbl)	(14.49)			(16.19)			(14.25)			(14.13)		

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement, the realized benefit or loss is recognized in oil and natural gas revenue.

At March 31, 2023, the Company held the following physical commodity contracts:

	Q2 2023
Mixed Sweet Blend Differential (MSW)	
Volume (bbls/d)	2,086
Average Fixed Price (USD/bbl)	(2.18)

Subsequent to March 31, 2023, the Company has not entered into any physical commodity contracts.

Royalties

	Three months ended March 31,			
	2023	2022		% change
Royalty expenses (\$ thousands)	\$73,292	\$58,483		25
\$/boe	11.99	15.72		(24)
Percent of sales (%)	19	20		(5)

Royalties as a percentage of revenue for the three months ended March 31, 2023, were lower than the same period in 2022 due to the sliding scale nature of some oil royalties, which fluctuate with commodity prices, partly offset by the addition of the gross overriding royalties (“GORRs”) in conjunction with the acquisitions that closed in 2022. As per the guidance included in this MD&A the Company expects royalty rates as a percentage of revenue to be in the 19% to 21% range for 2023 based on current forecast commodity pricing levels and increased production from lands subjected to GORRs.

On an absolute basis, royalty expense was higher in Q1/23 compared to the same period in 2022 due to an increase in production and GORRs.

Net Production Expenses

(\$ thousands, except per boe)	Three months ended March 31,		
	2023	2022	% change
Production expenses	\$65,040	\$38,286	70
Less: processing income	909	641	42
Total net production expenses ⁽¹⁾	\$64,131	\$37,645	70
Total (\$/boe) ⁽²⁾	\$10.49	\$10.12	4

⁽¹⁾ Non-IFRS Financial Measure; See "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures" section of this MD&A.

⁽²⁾ Non-IFRS Financial Ratio; See "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures" section of this MD&A.

For the three months ended March 31, 2023, per unit net production expenses (see "Non-IFRS Financial Ratios") were higher compared to the same period in 2022. This was primarily driven by prior period adjustments for non-operated properties along with lower production due to unscheduled downtime of third-party facilities and higher utility costs.

For the three months ended March 31, 2023, on an absolute basis gross and net production expenses were higher compared to the same period in 2022 due to higher production and higher per unit net production expenses as discussed above.

The 2023 production expense outlook remains in line with our previous guidance of \$9.00 to \$9.50 per boe as our new facilities are brought on-line in the second half of 2023 in conjunction with further synergies being realized across our Clearwater assets in the Nipisi and Marten Hills area.

Transportation Expense

(\$ thousands, except per boe)	Three months ended March 31,		
	2023	2022	% change
Transportation expense - gas	\$2,710	\$2,868	(6)
Transportation expense - oil	21,128	4,378	383
Total transportation expense	\$23,838	\$7,246	229
Total (\$/boe)	\$3.90	\$1.95	100

Transportation expense includes clean oil trucking and certain pipeline costs dependent on marketing arrangements.

For the three months ended March 31, 2023, per unit transportation expenses were higher compared to the same period in 2022. The increase in oil transportation was primarily driven by an increase in heavy oil production as a result of the acquisitions undertaken in 2022. In conjunction with the Deltastream acquisition, the transportation associated with the Rangeland Pipeline is now included in transportation expense as Tamarack markets this production. The natural gas transportation expense was relatively flat over the first quarter of 2023 compared to the same period in 2022.

For the three months ended March 31, 2023, total transportation expenses were higher compared to the same period in 2022 driven by the higher production, primarily heavy oil with both organic and acquisition growth in the Clearwater oil play.

Blending Expense

Blending expense includes the cost of blending diluent purchased to reduce the viscosity of our heavy oil transported through pipelines to meet pipeline specifications. The blending expense represents the difference between the cost of purchasing and transporting the diluent and the realized price of the blended product sold. In this MD&A, blending expense is recognized as a reduction to heavy oil revenues (see “Non-IFRS Financial Measures”).

Blending expense for the three months ended March 31, 2023 was \$1.8 million compared to \$nil in the same period in 2022. The Company recognized blending expense for the first time in Q4/22 as a result of the Deltastream acquisition which closed in October 2022.

Operating Netback

(\$/boe)	Three months ended March 31,		
	2023	2022	% change
Average realized sales, net of blending expense ⁽¹⁾	\$61.61	\$80.17	(23)
Royalty expenses	(11.99)	(15.72)	(24)
Net production expenses ⁽¹⁾	(10.49)	(10.12)	4
Transportation expense	(3.90)	(1.95)	100
Operating field netback ⁽¹⁾	\$35.23	\$52.38	(33)
Realized hedging loss	(1.06)	(4.00)	(74)
Operating netback ⁽¹⁾	\$34.17	\$48.38	(29)

	Three months ended March 31,		
	2023	2022	% change
Average realized sales, net of blending expense ⁽²⁾	\$376,720	\$298,254	26
Royalty expenses	(73,292)	(58,483)	25
Net production expenses ⁽²⁾	(64,131)	(37,645)	70
Transportation expense	(23,838)	(7,246)	229
Operating field netback ⁽²⁾	\$215,459	\$194,880	11
Realized hedging loss	(6,504)	(14,867)	(56)
Operating netback ⁽²⁾	\$208,955	\$180,013	16

⁽¹⁾ Non-IFRS Financial Ratio; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

⁽²⁾ Non-IFRS Financial Measure; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

For the three months ended March 31, 2023, operating netback per boe (see “Non-IFRS Financial Ratios”) was lower than the same period in 2022 primarily due to a decrease in commodity prices and higher net production and transportation expenses. On an absolute basis operating netback (see “Non-IFRS Financial Measures”) was higher for Q1 2023 compared to the same period in 2022 due to higher production from acquisitions that closed in 2022, partially offset by lower commodity prices, higher royalties, higher net production expenses and higher transportation expenses.

General and Administrative (“G&A”) Expenses

(\$ thousands, except per boe)	Three months ended March 31,		
	2023	2022	% change
Gross costs	\$10,602	\$10,175	4
Capitalized costs and recoveries	(2,803)	(1,685)	66
General and administrative costs	\$7,799	\$8,490	(8)
Total (\$/boe)	\$1.28	\$2.28	(44)

Net G&A costs on a per boe basis for the three months ended March 31, 2023, were lower compared to the same period in 2022 due to increased production from the acquisitions that closed in 2022, partially offset by increased staffing levels and growth-related cost increases.

For the three months ended March 31, 2023, gross G&A costs were higher compared to the same period in 2022, due to increased staffing levels and other Company growth-related cost increases.

Stock-Based Compensation Expense

(\$ thousands, except per boe)	Three months ended March 31,		
	2023	2022	% change
Stock Options	\$55	\$38	45
RSUs	1,705	815	109
PSUs	644	1,082	(40)
Equity settled	\$2,404	\$1,935	24
RSUs	\$(504)	\$ –	–
PSUs	960	–	–
RIAs	663	116	472
PIAs	566	190	198
Cash settled	\$1,685	\$306	451
Total capitalized costs	\$(1,303)	\$(709)	84
Total expensed stock-based compensation	\$2,786	\$1,532	82
Total (\$/boe)	\$0.46	\$0.41	12

Pursuant to the Company’s stock option plan, the Company’s performance and restricted share unit plan (the “PRSU Plan”) and the Company’s cash award incentive plan (the “CAI Plan”), the Company may grant up to an aggregate of 39.0 million stock options (“Stock Options”), restricted share units (“RSUs”), performance share units (“PSUs”), restricted incentive awards (“RIAs”) and performance incentive awards (“PIAs”) to officers, employees, directors and consultants of the Company or its subsidiaries, as applicable.

Stock-based compensation expense related to Stock Options, RSUs, PSUs, RIAs and PIAs for the three months ended March 31, 2023, was higher compared to the same period in 2022 primarily due to an increased number of equity-settled grants and the impact of common share prices on the cash-settled units as compared to the same period in 2022.

During the three months ended March 31, 2023, the Company issued 1.9 million RSUs, 1.3 million PSUs, 0.3 million RIAs and 1.1 million PIAs compared to 1.2 million RSUs, 1.2 million PSUs, 0.4 million RIAs and 1.0 million PIAs during the same period in 2022.

Finance Expense

(\$ thousands, except per boe)	Three months ended March 31,		
	2023	2022	% change
Interest and fees on SLL Facility	\$8,155	\$4,761	71
Interest and fees on Term Facility	5,107	–	–
Interest and fees on SL Notes	6,059	2,249	169
Interest on DAP Notes	3,685	–	–
Interest on lease liabilities	180	181	(1)
Accretion on government loan and Facilities acquisition payments	354	–	–
Other interest	2,560	–	–
Unrealized gain on foreign exchange	(8,810)	(5,751)	53
Unrealized loss on cross-currency swap	8,242	5,819	42
Accretion of decommissioning obligations	2,253	1,288	75
Total finance expense	\$27,785	\$8,547	225
Total (\$/boe)	\$4.54	\$2.30	97
Average drawings on credit facilities	\$717,690	\$368,496	95
Average drawings on SL Notes	\$300,000	\$130,273	130
Average drawings on DAP	\$256,111	\$–	–

Total finance expense for the three months ended March 31, 2023, was higher compared to the same period in 2022 due to higher interest rates on higher average drawings on the credit facilities due to the acquisitions throughout 2022, the interest on SL Notes issued in the first and third quarters of 2022, and interest on the Deferred Acquisition Payment Notes (“DAP Notes”) issued in the fourth quarter of 2022. Canadian interest rates have increased in 2023 compared to the same period in 2022. The interest rate on SL Notes issued in Q1/22 and Q3/22 is higher than rates on revolving borrowings. Interest and fees on the SLL Facility and SL Notes includes the amortization of fees associated with these facilities (See Debt on page 17).

Depletion, Depreciation and Amortization (“DD&A”)

(\$ thousands, except per boe)	Three months ended March 31,		
	2023	2022	% change
Depletion and depreciation	\$157,537	\$68,973	128
Amortization of undeveloped leases	769	229	236
Total	\$158,306	\$69,202	129
Depletion and depreciation (\$/boe)	\$25.76	\$18.54	39
Amortization (\$/boe)	0.13	0.06	117
Total (\$/boe)	\$25.89	\$18.60	39

For the three months ended March 31, 2023, DD&A expense per boe was higher relative to the same period in 2022. The increase was due to acquisitions that closed in 2022 that have a higher DD&A expense per boe than the corporate average.

On an absolute basis, DD&A expense was higher for the three months ended March 31, 2023, due to higher production and higher DD&A expense per boe.

Impairment (Impairment Reversal) of Property, Plant and Equipment and Exploration and Evaluation Assets

The Company has considered the impact of the evolving worldwide demand for energy and the global advancement of alternative sources of energy not sourced from fossil fuels in the estimates and judgments involved in its assessment of impairment and impairment reversal on its oil and gas properties. The estimated recoverable amount of the Company's oil and gas properties was based on proved and probable reserves, the life of which is generally less than 20 years.

As at March 31, 2023 there were no indicators of impairment or reversal of impairment identified on any of the Company's CGUs within property, plant and equipment and exploration and evaluation assets and no impairment or reversal of impairment test was performed.

Current Income Tax (Asset) Liability

(\$ thousands)	Three months ended March 31, 2023	Year ended December 31, 2022
Balance, beginning of the period	\$123,924	\$ –
Payments	(124,114)	–
Current income tax expense	20,289	75,849
Acquired income tax payable	–	48,075
Current income tax instalments	(22,391)	–
Balance, end of the period	\$(2,292)	\$123,924

For the three months ended May 31, 2023, the Company recorded current income tax expense of \$20.3 million (March 31, 2022 – \$17.7 million).

For the three months ended March 31, 2023, the Company recorded a deferred income tax recovery of \$12.1 million (March 31, 2022 – \$8.4 million).

Adjusted Funds Flow and Net Income

(\$ thousands, except per share amounts)	Three months ended March 31,		
	2023	2022	% change
Cash flow from operating activities	\$59,624	\$132,853	(55)
Current income tax expense	(20,289)	–	–
Income tax paid	146,505	–	–
Interest expense, excluding fees	(24,188)	–	–
Interest paid	16,268	–	–
Decommissioning expenditures	875	437	100
Changes in non-cash working capital	(21,524)	33,291	(165)
Adjusted funds flow ⁽¹⁾	\$157,271	\$166,581	(6)
Per share - basic ⁽²⁾	\$0.28	\$0.40	(30)
Per share - diluted ⁽²⁾	\$0.28	\$0.39	(28)
Net income	\$2,505	\$26,457	(91)
Per share - basic	\$ –	\$0.06	(100)
Per share - diluted	\$ –	\$0.06	(100)

⁽¹⁾ Capital Management Measure; See "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures" section of this MD&A.

⁽²⁾ Supplemental Financial Measure; See "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures" section of this MD&A.

Adjusted funds flow (see “Non-IFRS Financial Measures”) and cash flow from operating activities for the three months ended March 31, 2023 were lower compared to the same period in 2022 primarily due to lower commodity prices, the disposition of non-core Viking oil CGU assets in Q3/22, higher interest expense, higher current income tax expense and higher production and transportation costs, partially offset by an increase in revenue resulting from additional production due to acquisitions completed in 2022.

The Company recorded net income of \$2.5 million (\$0.00 per share basic and diluted) during the three months ended March 31, 2023 compared to net income of \$26.5 million (\$0.06 per share basic diluted) in the same period in 2022.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

The following table summarizes capital spending, excluding non-cash items:

(\$ thousands)	Three months ended March 31,		
	2023	2022	% change
Drilling, completion and equipping	\$96,571	\$91,073	6
Facilities	50,001	13,841	261
Land, seismic and other	1,590	20,453	(92)
Exploration and development expenditures	\$148,162	\$125,367	18
Property acquisitions	2,939	–	–
Proceeds from dispositions	(180)	–	–

During the first quarter of 2023, the Company drilled, completed and equipped, thirty-two (32.0 net) Clearwater oil wells and eight (7.8 net) Charlie Lake oil wells.

For the three months ended March 31, 2023 approximately \$30 million of facility expenditures were related to the Company’s drilling program and approximately \$20 million of facility expenditures were related to major infrastructure projects including pipeline installations related to the 2023 Nipisi Gas Conservation Program, construction of a gas plant in the Wembley area and the construction of an oil treating and water injection facility in the Nipisi area.

On January 6, 2023 the Company acquired assets in the Charlie Lake oil CGU for cash consideration of approximately \$2.9 million. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquisition being accounted for as an asset acquisition. As such the purchase price of the minor acquisition was allocated to the identifiable assets and liabilities based on their relative fair values at the date of the acquisition.

For the three months ended March 31, 2023 the Company disposed of non-core properties for proceeds of \$0.2 million.

Subsequent to March 31, 2023 the Company disposed of approximately 400 boe/d of certain non-core properties for proceeds of \$2.3 million.

Share Capital

(\$ thousands)	March 31, 2023		December 31, 2022	
	Number	Amount	Number	Amount
Balance, opening	556,440,901	\$1,879,250	406,938,099	\$1,242,392
Issue of common shares - cash	–	–	38,334,100	143,753
Issue of common shares - acquisitions	–	–	115,575,033	515,402
Issue of common shares - Option, RSU and PSU exercise	359,894	–	3,485,469	–
Purchase of common shares - cancellation	–	–	(4,362,700)	(14,375)
Return of common shares to treasury	–	–	–	(2,646)
Purchase of common shares - Option, RSU and PSU exercise	–	–	(3,529,100)	–
Share issue costs, net of tax (2023 - \$nil; 2022 - \$1,576)	–	–	–	(5,276)
Balance, ending	556,800,795	\$1,879,250	556,440,901	\$1,879,250

(thousands)	May 10, 2023	March 31, 2023	December 31, 2022
Common shares outstanding	556,798	556,801	556,441
Common shares held in treasury	146	140	500
Options outstanding - equity-settled	1,254	1,254	1,378
RSUs outstanding - equity-settled	4,905	4,990	3,430
PSUs outstanding - equity-settled	2,617	2,765	1,968

Liquidity and Capital Resources

(\$ thousands)	March 31, 2023	December 31, 2022
Working capital deficiency ⁽¹⁾	\$85,822	\$161,185
Note receivable	(20,000)	(20,000)
Credit facilities	791,663	650,848
SL Notes	288,388	287,691
DAP Notes	206,667	256,667
Government loan and Facilities acquisition payments	21,528	20,179
Net debt ⁽¹⁾	\$1,374,068	\$1,356,570
Quarterly adjusted funds flow ⁽¹⁾	\$157,271	\$196,746
Annualized factor	4	4
Annualized adjusted funds flow ⁽¹⁾	\$629,084	\$786,984
Net debt to annualized adjusted funds flow ⁽¹⁾	2.2x	1.7x

⁽¹⁾ Capital Management Measure; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

Tamarack’s strategy remains focused on preserving balance sheet strength. The Company strives to achieve this by managing capital spending levels as appropriate to respond to changes in realized commodity prices and through the systematic hedging program using both financial derivatives and physical delivery contracts to mitigate risk. The Company generally relies on adjusted funds flow and its credit facilities to fund its capital requirements, return of capital and provide liquidity.

Tamarack’s net debt, including working capital deficiency (see “Capital Management Measures”), totaled \$1,374.1 million as at March 31, 2023. This compares to the Company’s net debt of \$556.4 million as at March 31, 2022 and \$1,356.6 million as at December 31, 2022. Tamarack’s Q1/23 net debt to annualized adjusted funds flow ratio (see “Capital Management Measures”) was 2.2 times.

The Company's \$150.9 million investment in capital additions, inclusive of acquisitions and dispositions, during Q1/23 was fully funded by Tamarack's adjusted funds flow (see "Capital Management Measures") of \$157.3 million. The Q1/23 increase in the Company's net debt of \$17.5 million as compared to December 31, 2022 was primarily due to changes in working capital and repayment of DAP Notes, partially offset by changes in the SLL Facility.

The Company believes that increased available credit facilities combined with anticipated adjusted funds flow will be sufficient to satisfy Tamarack's 2023 development capital program, dividend payments for the 2023 fiscal year and DAP Notes and Term Facility amortization payments required in 2023.

Pursuant to the Company's approved normal course issuer bid ("NCIB"), the Company is permitted to purchase up to 27.8 million Common Shares over a period of 12 months commencing on January 19, 2023. During the three months ended March 31, 2023, the Company did not purchase or cancel any Common shares.

During the three months ended March 31, 2023, the Company declared \$20.9 million related to its monthly cash dividends on common shares of \$0.0125 per share and has accrued a dividend payable of \$7.0 million for the dividend declared on March 15, 2023.

These monthly cash dividends are designated as "eligible dividends" for Canadian income tax purposes.

Debt

(\$ thousands)	March 31, 2023	December 31, 2022
Current Debt		
Credit Facilities		
Term Facility	\$ 86,667	\$ 65,000
DAP Notes	200,000	200,000
	\$ 286,667	\$ 265,000
Long-term Debt		
Credit Facilities		
SLL Facility	\$ 556,663	\$ 415,848
Term Facility	148,333	170,000
Credit Facilities total	\$ 704,996	\$ 585,848
SL Notes	288,388	287,691
DAP Notes	6,667	56,667
	\$ 1,000,051	\$ 930,206
Total Debt	\$ 1,286,718	\$ 1,195,206

(a) Credit Facilities:

On October 13, 2022, the Company established a new three-year covenant-based SLL facility, replacing the existing SLL facility. The SLL facility increased to \$700.0 million and is paired with a \$260.0 million two-year secured amortizing term-loan ("Term Facility") from a syndicate of lenders for a total lending capacity of \$960.0 million. The SLL Facility and the Term Facility collectively constitute a "Syndicated Facility". The Syndicated Facility is secured by a \$2.0 billion debenture with fixed coverage over all the assets of the Company. The SLL portion of the facility bears interest at the applicable rate for the borrowing employed plus a credit margin based on the senior debt to EBITDA ratio of the Company.

As the Syndicated Facility is a covenant-based facility, it is not contingent on the reserve base of the Company and not subject to annual or semi-annual redeterminations. The Syndicated Facility may be reviewed for extension, of term or amount, once annually at the discretion of the borrower. There are no mandatory principal repayments required prior to maturity.

Subsequent to March 31, 2023 the Credit Facilities went through a review which resulted in an extension of the SLL Facility maturity date from October 2025 to May 2026 and an increase to \$875.0 million. Concurrently, the Term Facility was decreased to \$200.0 million for a total lending capacity of \$1,075.0 million.

SLL Facility:

The SLL Facility contains commercial covenants and sustainability adjustments in addition to financial covenants detailed below.

A total of \$556.7 million was drawn as of March 31, 2023 (December 31, 2022 – \$415.8 million). The interest rate applicable to the drawn amounts as of this date was 6.88% (December 31, 2022 – 6.21%).

The Company manages its SLL Facility using a combination of prime rate loans, BA notes and US dollar denominated secured overnight financing rate (“SOFR”) loans. Concurrent with the drawdown of US dollar SOFR loans, the Company may enter into cross-currency swaps (“CCS”) to fix the foreign exchange on US dollar SOFR loan amounts for purposes of interest and principal repayments. At March 31, 2023, the Company had drawn US\$425.0 million, fixed at notional amounts of \$583.4 million through CCS maturing across the month of April 2023 (December 31, 2022 – the Company had drawn US\$290.0 million, fixed at notional amounts of \$393.5 million through various CCS).

Term Facility:

The Term Facility is a covenant-based, non-revolving facility with a maturity date of October 13, 2024, and may be extended for a single 12-month term at the request of the borrower and the discretion of the lenders. Minimum quarterly amortization payments of \$21.7 million commenced in Q1 2023. If the Company determines it has generated Excess Cash Flow as defined by the Syndicated Facility agreement, the minimum required payment for the quarter will be the greater of fifty percent (50%) of the determined Excess Cash Flow and the minimum amortization payment. The balance remaining after all quarterly payments over the two-year term of the Term Facility is due and payable at maturity. The Term Facility bears interest at the applicable rate for the borrowing employed plus a fixed margin rate. The Company made its Q1 2023 payment on December 30, 2022, of \$25.0 million in accordance with the agreement due to proceeds on disposition of a non-core property in December, which, as defined in the agreement, are required to be applied to the Term Facility. The Syndicate has agreed to apply these proceeds first to the Q1 2023 amortization payment with the remaining proceeds applied to the balance at maturity. No further amortization payments were required to be made during the quarter.

A total of \$235.0 million was drawn as of March 31, 2023 (December 31, 2022 – \$235.0 million). The average interest rate applicable to the drawn amounts as of this date was 8.68% (December 31, 2022 – 8.38%).

Financial Covenants:

The following table summarizes the financial covenants applicable to the Syndicated Facility and Term Facility at March 31, 2023:

Covenant Description	Position as at March 31, 2023	Covenant ⁽⁵⁾
Total Debt ⁽¹⁾ to EBITDA ⁽²⁾ Ratio	1.1:1.0	<3.0:1.0
Senior Debt ⁽³⁾ to EBITDA ⁽²⁾ Ratio	0.7:1.0	<2.5:1.0
Debt Service Coverage ⁽⁴⁾ Ratio	3.2:1.0	>1.5:1.0

⁽¹⁾ “Total Debt” is calculated in accordance with the credit facility agreements as all Debt of the Company excluding capitalized lease obligations and Letters of Credit of \$5.0 million outstanding as at March 31, 2023 and including indebtedness under the deferred acquisition notes issued on closing of the Deltastream acquisition.

⁽²⁾ “EBITDA” is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on the previous four quarters including the impact of material acquisitions as if they had occurred at the beginning of the four quarters.

⁽³⁾ “Senior Debt” is calculated in accordance with the credit facility agreements as Total Debt minus the SL Notes and permitted junior debt, including the Deferred Acquisition Payment Notes.

⁽⁴⁾ “Debt Service Coverage” is calculated as the ratio of EBITDA to cash interest expense plus scheduled principal payments on Total Debt for the twelve months ending at the end of each fiscal quarter.

⁽⁵⁾ Covenants in effect while the Term Facility and Deferred Acquisition Payment Notes are outstanding after which time the covenants will change to 3.5:1.0, 3.0:1.0 and 3.0:1.0, respectively.

(b) SL Notes:

During 2022, the Company issued \$300.0 million aggregate principal amount of 7.25% senior unsecured sustainability-linked notes due May 10, 2027 (“SL Notes”). The SL Notes were offered through private placement underwriting agreements entered into in 2022. The SL Notes were issued under a trust indenture and are general unsecured obligations of Tamarack ranking pari passu with all of the Company’s existing and future senior unsecured indebtedness.

As at March 31, 2023 the carrying value of the SL Notes of approximately \$288.4 million was net of approximately \$11.6 million of discounts and unamortized deferred financing costs incurred in conjunction with the issuance of the SL Notes. As at March 31, 2023 there was \$300.0 million principal outstanding on the SL Notes (December 31, 2022 – \$300.0 million). The next coupon payment date is set for May 10, 2023, in the amount of approximately \$10.9 million.

(c) Deferred Acquisition Payment (“DAP”) Notes:

On October 13, 2022, the Company issued \$300.0 million aggregate principal amount of DAP Notes. There are no financial covenants governing the DAP Notes. The DAP Notes were issued under a trust indenture and are unsecured and payable in cash quarterly over an 18-month period in an amount equal to the lesser of \$50.0 million and the aggregate principal amount of all outstanding notes.

On March 31, 2023, the Company made its second principal payment in the amount of \$50.0 million. Interest on the DAP Notes is incurred at 5.75% per annum and is paid quarterly in arrears. The Company paid \$3.7 million of interest related to the second quarterly interest requirement concurrent with the first principal payment. The next payment date is set for June 30, 2023.

At March 31, 2023 the aggregate outstanding principal of the DAP Notes is approximately \$206.7 million (December 31, 2022 – \$256.7 million).

Commitments

The following table summarizes the Company’s commitments as at March 31, 2023:

(\$ thousands)	2023	2024	2025	2026	2027+
Bank debt ⁽¹⁾	65,000	170,000	556,663	–	–
SL Notes ⁽²⁾	–	–	–	–	300,000
Interest on SL Notes ⁽²⁾	21,750	21,750	21,750	21,750	7,746
DAP Notes ⁽³⁾	150,000	56,667	–	–	–
Interest on DAP Notes ⁽³⁾	6,779	826	–	–	–
Lease obligations	5,119	3,585	2,566	418	467
Government loan ⁽⁴⁾	–	–	1,939	6,601	12,295
Take or pay commitments ⁽⁵⁾	16,313	17,903	18,337	16,308	50,500
Processing commitments ⁽⁶⁾	2,398	3,038	9,276	9,276	67,305
Gas transportation ⁽⁷⁾	4,854	4,367	464	102	33
Capital commitments ⁽⁸⁾	10,620	25,722	–	–	–
Total	282,833	303,858	610,995	54,455	438,346

⁽¹⁾ Term Facility matures on October 13, 2024 with quarterly amortization payments. SLL Facility matures on October 13, 2025 with no mandatory principal repayments prior to maturity. Excludes interest on SLL Facility as interest payments fluctuate based on floating rates of interest and changes in the outstanding balance. Subsequent to March 31, 2023 the Company extended the SLL Facility to a maturity of May 5, 2026.

⁽²⁾ Principal amount of the SL Notes. SL Notes bear a coupon rate of 7.25%, payable semi-annually in arrears.

⁽³⁾ Principal amount of the DAP Notes. DAP Notes bear a coupon rate of 5.75%, payable quarterly.

⁽⁴⁾ Relates to the scheduled payments on the repayable government loan funding received from the Government of Canada under the terms of the ERF agreement.

⁽⁵⁾ Pipeline commitments to deliver crude oil and/or crude oil and condensate for various volumes ranging from minimums of 65 m3/d to 1,589 m3/d at various tariffs ranging from \$9.00/m3 to \$25.22/m3 which expire between June 30, 2023 and December 31, 2030. Certain of these pipeline commitments escalate at 2% per annum.

⁽⁶⁾ Processing commitments to guarantee firm processing capacity in various facilities.

⁽⁷⁾ Gas transportation costs on long term firm contracts which are in various locations at variable rates.

⁽⁸⁾ Initial aggregate commitments of \$240.0 million of capital to further develop the GORR Nipisi/Clearwater and Grande Prairie lands prior to March 31, 2024.

Climate Change and Sustainability

Tamarack continues to consider the impact of climate change and the financial and operational challenges this global concern has had in 2023 and the continuing impact on the Company during the years ahead.

Climate Change

The Company has considered and continues to consider the impact of the evolving worldwide demand for carbon-based energy and global advancement of alternative energy sources.

Emissions, carbon and other regulations impacting climate and climate related matters, are constantly evolving. With respect to ESG and climate reporting, the International Sustainability Standards Board (“ISSB”) was created on November 3, 2021 with the aim to develop globally consistent, comparable and reliable sustainability disclosure standards. On March 31, 2022, the ISSB issued exposure drafts *IFRS S1 “General Requirements for Disclosure of Sustainability-related Financial Information”* and *IFRS S2 “Climate-related Disclosures”*, which exposure drafts closed for comment on July 29, 2022. The ISSB redeliberated the proposals after considering the feedback on the exposure drafts and expects to issue the IFRS sustainability disclosure standards around the end of Q2 2023. The ISSB tentatively decided in February 2023 to require that *IFRS S1* and *IFRS S2* be effective for annual reporting periods beginning on or after January 1, 2024. The ISSB tentatively decided to introduce a transition relief in *IFRS S1* that would allow an entity to report on only climate-related risks and opportunities, as set out in *IFRS S2*, in the first year it applies *IFRS S1* and *IFRS S2*. The Company is not able at this time to determine the impact on future financial statements that may result from these exposure drafts until a ballot is completed and the standards ratified. In addition, the Canadian Securities Administrators have issued a proposed National Instrument (“NI 51-107”) - *Disclosure of Climate-related Matters*. The cost to comply with these standards, and others, that may be developed or evolved over time, is not quantifiable at this time. Significant estimates and judgments have been made by management in the preparation of the financial statements in areas of property, plant and equipment, exploration and evaluation assets, depletion, impairment and impairment reversal, reserves estimates, decommissioning obligations, credit facilities and share capital.

Sustainability

Tamarack is committed to the continued advancement of our ESG practices as outlined in our third annual Sustainability Report released on December 19, 2022. This report provides details on the Company’s approach to sustainability, including our commitments to GHG emissions management and to continued Indigenous and community partnerships in the areas where we operate. In addition, the report highlights specific, measurable goals and targets related to key focus areas set by the Company.

Based on the Company’s commitment and approach to sustainability, the Company amended its revolving bank facility to a Sustainability-Linked Lending Facility (“SLL Facility”) in late 2021 which incorporates sustainability-linked interest rate terms (see Debt on page 17). During the first quarter of 2022 the Company issued \$200.0 million aggregate principal amount of 7.25% senior unsecured sustainability-linked notes (“SL Notes”) due May 10, 2027 and an additional \$100.0 million aggregate principal amount of SL Notes due May 10, 2027 in the third quarter of 2022 (see Debt on page 17).

Contingency

During 2019, the Company was served with a Statement of Claim from two joint interest owners that hold minority interests in a Unit, which is majority owned and operated by the Company. The plaintiffs are seeking judgment in the amount of \$56.0 million for unlawful conversion of their minority Unit interests (such amount based upon the alleged value of their minority Unit interests) or alternatively, judgment in the amount of \$1.65 million, representing the amounts allegedly owed by the Company plus punitive damages, interest and other costs. The minority Unit owners have also alleged Tamarack has breached the Company’s fiduciary duties owing to the minority Unit owners and that without the approval of the minority Unit owners, the Company has conducted operations within the Unit area and outside of the Unit area without the approval of the minority Unit owners.

The Company has filed a Statement of Defence denying all material allegations of the minority Unit owners. The Company believes the claims are without merit and the amounts are unsubstantiated. Therefore, no provision for any amount has been recorded in the financial statements.

Unit Cost Calculation

For the purpose of calculating unit costs, natural gas volumes have been converted to a boe using six thousand cubic feet equal to one barrel, unless otherwise stated. A boe conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion complies with the Canadian Securities Administrators' National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). Boe may be misleading, particularly if used in isolation.

Abbreviations

AECO	Alberta Energy Company benchmark for natural gas
Bbl(s)	barrel(s)
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
CGU	cash-generating unit
GJ	gigajoule
GJ/d	gigajoule per day
IFRS	International Financial Reporting Standards
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbtu	one million British thermal units
mmbtu/d	one million British thermal units per day
MSW	mixed sweet blend, the benchmark for conventionally produced light sweet crude oil in Western Canada
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
WCS	Western Canadian Select, the benchmark for both conventionally produced and oilsands produced heavy sour crude oil in Western Canada
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures

This document contains the terms "net production expenses", "revenue, net of blending expense", "operating netback" and "operating field netback", which are non-IFRS financial measures, or ratios if calculated on a per boe basis. The Company uses these measures to help evaluate Tamarack's performance. These non-IFRS financial measures and ratios do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers. This document also contains the capital management measures of "adjusted funds flow", "net debt", "working capital deficiency", "net debt to annualized adjusted funds flow", "capital expenditures" and "free funds flow".

- (a) Adjusted Funds Flow (Capital Management Measure)** - Adjusted funds flow is calculated by taking cash-flow from operating activities on a periodic basis, deducting current income tax expense and interest expense excluding fees, adding back income tax paid, interest paid, expenditures on decommissioning obligations and transaction costs and deducting or adding back changes in non-cash working capital, as required. Management believes adjusting for estimated current income taxes and interest in the period expensed is a better indication of the adjusted funds generated by the Company. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available

adjusted funds flow. Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt, pay dividends and fund future capital investment. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares that are used in calculating income per share, which results in the measure being considered a supplemental financial measure. Adjusted funds flow can also be calculated on a per boe basis, which results in the measure being considered a supplemental financial measure. The calculation of the Company's adjusted funds flows is summarized starting on page 14 in the section titled "Adjusted Funds Flow and Net Income."

(b) Net Production Expenses, Revenue, net of blending expense, Operating Netback and Operating Field Netback (Non-IFRS Financial Measures, and Non-IFRS Financial Ratios if calculated on a per boe basis) -

Management uses certain industry benchmarks, such as net production expenses, revenue, net of blending expense, operating netback and operating field netback, to analyze financial and operating performance. 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. Under IFRS this source of funds is required to be reported as income. Where the Company has excess capacity at one of its facilities, it will process third party volumes as a means to reduce the cost of operating/owning the facility, and as such third-party processing revenue is netted against production expenses in the MD&A. Blending expense includes the cost of blending diluent purchased to reduce the viscosity of our heavy oil transported through pipelines to meet pipeline specifications. The blending expense represents the difference between the cost of purchasing and transporting the diluent and the realized price of the blended product sold. In this MD&A, blending expense is recognized as a reduction to heavy oil revenues, whereas blending expense is reported as an expense in the financial statements. Operating netback equals total petroleum and natural gas sales (net of blending), including realized gains and losses on commodity and foreign exchange derivative contracts, less royalties, net production expenses and transportation expense. Operating field netback equals total petroleum and natural gas sales, less royalties, net production expenses and transportation expense. These metrics can also be calculated on a per boe basis, which results in them being considered a non-IFRS financial ratio. Management considers operating netback and operating field netback important measures to evaluate Tamarack's operational performance, as it demonstrates field level profitability relative to current commodity prices. The calculation of the Company's netbacks can be seen starting on page 11 in the section titled "Operating Netback".

(c) Net Debt and Working Capital Deficiency (Capital Management Measure) -

Tamarack closely monitors our 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 our capital structure. The Company uses net debt (Credit facilities plus SL Notes plus DAP Notes plus Government loan plus Facilities acquisition payments less Note receivable plus working capital surplus or deficiency, excluding the current portion of fair value of financial instruments, decommissioning obligations, lease liabilities and the cash award incentive plan liability) as an alternative measure of outstanding debt. Management considers net debt an important measure to assist in assessing the liquidity of the Company.

The following outlines the Company's calculation of net debt:

(\$ thousands)	March 31, 2023	December 31, 2022
Accounts payable and accrued liabilities	\$240,488	\$220,568
Current income tax (asset) liability	(2,292)	123,924
Cross currency swap liability	8,995	753
Accounts receivable	(151,289)	(177,218)
Prepaid expenses and deposits	(10,080)	(6,842)
Working capital deficiency	\$85,822	\$161,185
Note receivable	(20,000)	(20,000)
Credit facilities	791,663	650,848
SL Notes	288,388	287,691
DAP Notes	206,667	256,667
Government loan and Facilities acquisition payments	21,528	20,179
Net debt	1,374,068	1,356,570

(d) Net Debt to Annualized Adjusted Funds Flow (Capital Management Measures) - Management uses certain industry benchmarks, such as net debt to annualized adjusted funds flow, to analyze financial and operating performance. This benchmark is calculated as net debt divided by the annualized 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 the Company and our ability to fund capital requirements, dividend payments, pay off debt and take on new debt, if necessary, using the most recent quarter's results. The calculation of the Company's net debt to annualized adjusted funds flow can be seen starting on page 16 in the section titled "Liquidity and Capital Resources".

(e) Free Funds Flow and Capital Expenditures (Capital Management Measure) - Management uses certain industry benchmarks, such as free funds flow, to analyze financial and operating performance. This benchmark is calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions. Capital expenditures is calculated as property, plant and equipment additions (net of government assistance) plus exploration and evaluation additions. 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.

For the three months ended March 31,	2023	2022
Adjusted funds flow	\$157,271	\$166,581
Less: Property, plant and equipment expenditures	145,642	111,783
Government assistance	(611)	(4,442)
Exploration and evaluation expenditures	3,131	18,026
Capital expenditures	148,162	125,367
Free funds flow	\$9,109	\$41,214

Selected Quarterly Information

Three months ended	Mar. 31, 2023	Dec. 31, 2022	Sept. 30, 2022	Jun. 30, 2022	Mar. 31, 2022	Dec. 31, 2021	Sept. 30, 2021	Jun. 30, 2021
Sales volumes								
Natural gas (<i>mcf/d</i>)	74,293	68,355	62,428	67,195	70,989	74,291	72,935	60,887
Oil and NGL (<i>bbls/d</i>)	55,556	52,951	33,071	32,578	29,503	28,002	29,100	22,268
Average boe/d (6:1)	67,938	64,344	43,476	43,777	41,335	40,384	41,256	32,416
Product prices								
Natural gas (<i>\$/mcf</i>)	3.50	4.89	6.27	7.81	5.70	5.09	3.44	2.77
Oil and NGL (<i>\$/bbl</i>)	71.03	80.38	95.93	121.17	98.61	80.55	70.40	67.47
Oil equivalent (<i>\$/boe</i>)	61.91	71.34	81.98	102.16	80.17	65.21	55.73	51.55
<i>(000s, except per share amounts)</i>								
Financial results								
Gross revenues	378,546	422,313	327,910	406,971	298,254	242,288	211,527	152,061
Cash flow from operating activities	59,624	227,889	229,927	214,708	132,853	118,647	100,558	40,253
Adjusted funds flow ⁽²⁾	157,271	196,746	177,834	203,622	166,581	124,080	102,486	71,741
Per share – basic ⁽³⁾	0.28	0.36	0.40	0.47	0.40	0.31	0.25	0.21
Per share – diluted ⁽³⁾	0.28	0.36	0.40	0.46	0.39	0.30	0.25	0.21
Net income	2,505	50,441	124,793	143,507	26,457	140,448	20,032	230,194
Per share – basic	–	0.09	0.28	0.33	0.06	0.35	0.05	0.69
Per share – diluted	–	0.09	0.28	0.33	0.06	0.34	0.05	0.67
Capital expenditures ⁽²⁾	148,162	125,276	98,451	109,483	125,367	41,672	69,978	30,805
Acquisitions ⁽¹⁾	2,939	1,447,973	1,365	112,175	224,270	22,593	52,004	539,506
Dispositions ⁽¹⁾	(180)	(21,873)	(59,498)	(15,482)	–	(74)	(8,140)	(32,283)
Total assets	4,593,760	4,619,701	2,839,146	2,829,984	2,648,093	2,328,153	2,230,382	2,180,303
Net debt ⁽²⁾	1,374,068	1,356,570	286,762	470,563	556,374	463,284	519,708	505,992
Credit facilities (cash)	791,663	650,848	(97,509)	324,761	325,899	477,437	520,961	520,012
SL Notes	288,388	287,691	287,379	195,086	195,096	–	–	–
DAP Notes	206,667	256,667	–	–	–	–	–	–
Dividends declared per share	0.0375	0.0350	0.0300	0.0266	0.0249	–	–	–
Decommissioning obligations	265,374	264,988	237,813	238,768	270,458	284,472	265,929	264,791

⁽¹⁾ Includes cash and non-cash consideration.

⁽²⁾ Capital Management Measure; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

⁽³⁾ Supplemental Financial Measure; See “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures” section of this MD&A.

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

- The volatility in commodity prices and oil price differentials and the resulting effect on revenue, cash flow from operating activities, adjusted funds flows and earnings.
- The volatility in decommissioning obligations due to fluctuations in discount rates and acquisitions.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices, foreign exchange and interest rates which can cause significant fluctuations in earnings due to unrealized gains and losses recognized on a quarterly basis.
- On October 13, 2022, Tamarack closed the acquisition of Clearwater area properties. The assets include approximately 19,500 boe/d of oil weighted assets, along with adding 184 net sections in the Clearwater oil play of Alberta for a total purchase consideration of approximately \$1.4 billion.
- On July 21, 2022, Tamarack closed the disposition of non-Core Viking oil CGU assets for net consideration of approximately \$59.5 million (inclusive of a \$20.0 million promissory note at 12% interest maturing on July 21, 2025).

- On June 10, 2022, Tamarack closed the acquisition of Southern Clearwater area properties. The assets include approximately 2,100 boe/d of oil weighted assets, along with adding 34,560 net acres in the Southern Clearwater oil play of Alberta for a total purchase price of approximately \$108.1 million.
- On February 15, 2022, Tamarack closed the acquisition of Southern Clearwater area properties. The assets include approximately 3,500 boe/d of oil weighted assets, along with adding 153.7 net sections in the Southern Clearwater oil play of Alberta for a total purchase price of approximately \$228.3 million.
- On June 1, 2021, Tamarack closed the acquisition of Charlie Lake area properties in the Grande Prairie field of Alberta. The assets include approximately 11,800 boe/d of oil weighted assets, along with adding 349.7 net sections in the Charlie Lake oil play of Alberta for a total purchase price of approximately \$538.4 million.
- The Company recorded an impairment reversal in Q4/21 in the amount of \$90.0 million on the Viking oil CGU, Cardium oil CGU and Penny oil CGU due to increased current and forecasted oil and natural gas prices. The impairment reversal was recorded in the following CGUs: the Viking oil CGU reversed \$52.3 million, the Cardium oil CGU reversed \$14.3 million and the Penny oil CGU reversed \$23.4 million.
- The Company recorded an impairment reversal in Q2/21 in the amount of \$300.0 million on the Viking oil CGU and Cardium oil CGU due to increased current and forecasted oil and natural gas prices. The impairment reversal was recorded in the following CGUs: the Viking oil CGU reversed \$160.0 million and the Cardium oil CGU reversed \$140.0 million.

Critical Accounting Estimates

Management is required to make judgments, assumptions, and estimates in applying its accounting policies which have significant impact on the financial results of the Company. The following outlines the accounting policies involving the use of estimates that are critical to understanding the financial condition and results of operations of the Company:

- Oil and natural gas reserves** – Proved reserves, as defined by the Canadian Securities Administrators in NI 51-101 with reference to the Canadian Oil and Gas Evaluation Handbook, 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. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved and probable reserves.
- Carrying value of property, plant and equipment (“PP&E”)** – PP&E is measured at cost less accumulated depletion, depreciation, amortization, impairment losses and impairment reversals. The net carrying value of PP&E and estimated forecasted future development costs is depleted using the unit-of-production method based on estimated proved and probable oil and natural gas reserves. Changes in estimated proved and probable oil and natural gas reserves or forecasted future development costs have a direct impact on the calculation of depletion expense.

The Company is required to use judgment when designating the nature of oil and gas activities as exploration and evaluation (“E&E”) assets or oil and natural gas interests within PP&E. E&E assets and oil and natural gas interests are aggregated into CGUs based on their ability to generate largely independent cash inflows. The allocation of the Company’s assets into CGUs requires significant judgment with respect to the use of shared infrastructure, geographic proximity, existence of active markets for the Company’s products, the way in which management monitors operations and materiality.

Significant management judgments are required to analyze the relevant external and internal indicators of impairment or impairment reversal for a CGU with the estimate of proved and probable oil and natural gas reserves being significant to the assessment.

The Company assesses PP&E for impairment or impairment reversal whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. If any such indication of impairment or impairment reversal exists, the Company performs an impairment test related to the specific CGU. The determination of the estimated recoverable amount of a CGU is based on estimates of proved and probable oil and natural gas reserves. By their nature, these estimates of proved and probable oil and natural gas reserves are subject to uncertainty including significant assumptions related to forecasted oil and natural gas commodity prices, forecasted production, forecasted production costs, forecasted royalty costs and forecasted future development costs and the impact on the financial statements of future periods could be material.

The Company has considered the impact of the evolving worldwide demand for carbon-based energy and global advancement of alternative energy sources in its assessment of impairment and impairment reversal on its oil and gas properties, both as indicators of impairment and impairment reversal, and in the estimates and judgments involved in testing for impairment and impairment reversal. The estimated recoverable amount of the Company's oil and gas properties was based on proved and probable reserves, the life of which is generally less than 20 years. However, the ultimate period in which global energy markets can transition from carbon-based sources to alternative energy is highly uncertain. The Company will continue to monitor its estimates as the global demand for alternative energy sources continues to evolve.

- (c) **Decommissioning obligations** – The decommissioning obligations are estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a risk-free rate. The costs are included in PP&E and amortized over the useful life of the asset. The liability is adjusted each reporting period to reflect the passage of time, with the accretion expense charged to net earnings, and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.
- (d) **Income taxes** – The determination of income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.
- (e) **Business combinations** – The application of the Company's accounting policy for business combinations requires management to make certain judgments on a case-by-case basis as to the determination of the accounting method of an acquisition to determine if the assets acquired meet the definition of a business combination or an asset acquisition. In a business combination, management makes estimates of the acquisition-date fair value of assets acquired and liabilities assumed which includes assessing the estimated fair value of oil and natural gas interests (included in property, plant and equipment). The determination of the acquisition-date fair value of oil and natural gas interests involves significant estimates, including the estimate of proved and probable oil and natural gas reserves, the estimate of unbooked oil and natural gas reserves and the discount rates. The estimate of proved and probable oil and natural gas reserves and the estimate of unbooked oil and natural gas reserves includes significant assumptions related to: forecasted oil and natural gas commodity prices, forecasted production, forecasted production costs, forecasted royalty costs, forecasted future development costs and timing of development for the unbooked oil and natural gas reserves. The estimates of proved and probable oil and natural gas reserves and unbooked oil and natural gas reserves are prepared by the Company's external independent qualified reserves evaluator or internal qualified reserves evaluator.

Disclosure Controls and Internal Controls over Financial Reporting

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

The Company has designed internal controls over financial reporting (“ICFR”) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company’s ICFR that occurred during the recent fiscal period that has materially affected, or is reasonably likely to materially affect, the Company’s ICFR.

No material changes to the Company’s DCP and its ICFR were identified during the period ended March 31, 2023 that have materially affected, or are reasonably likely to materially affect, the Company’s internal controls over financial reporting. As a result, the Company’s DCP and ICFR were effective as at March 31, 2023.

It should be noted that a control system, including the Company’s disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute assurance that the objectives of the control system will be met, and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Business Risks

Tamarack faces business risks, both known and unknown, with respect to its oil and gas exploration, development, and production activities that could cause actual results or events to differ materially from those forecasts. Most of these risks (financial, operational or regulatory) are not within the Company’s control. While the following sections discuss some of these risks, they should not be construed as exhaustive. For additional information on the risks relating to Tamarack’s business, see “Risk Factors” in Tamarack’s Annual Information Form for the year ended December 31, 2022.

(a) Continued Volatility in Commodity and Petroleum Products Prices

Tamarack’s financial performance is significantly dependent on the prevailing prices of crude oil, refined products and natural gas. Crude oil prices are impacted by a number of factors, including, but not limited to: global and regional supply and demand; global economic conditions including factors impacting global trade and disruption of trade routes; the actions of OPEC and other non-OPEC oil exporting nations, including, but not limited to, compliance or non-compliance with production quotas agreed upon by OPEC members or decisions by OPEC not to impose production quotas on its members; development, adoption, pricing and availability of alternate sources of energy; actions of domestic and foreign governments, regulatory bodies and quasi-regulatory bodies that may impact commodity prices, including United States Strategic Petroleum Reserve withdrawals and refills; enforcement of environmental or emissions regulations; public sentiment towards the use of fossil fuels, including crude oil; political stability and social conditions in oil-producing countries; outbreak of war, including Russia’s military invasion of Ukraine; market access constraints and transportation interruptions (pipeline, marine or rail); outbreak or continuation of a pandemic; terrorist threats; technological developments; the occurrence of natural disasters; and weather conditions.

Certain difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the 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 oil and natural gas industry in western Canada has led to additional downward price pressure on oil and natural gas produced in western Canada. The overall impact of these market conditions and the potential for decreased confidence in the Canadian crude oil and natural gas industry could materially and adversely affect Tamarack's business, prospects, financial condition, results of operations and cash flows.

Ongoing military tensions between Russia and Ukraine have the potential to threaten the supply of oil and gas from the region. The long-term impacts of the tension between these nations remains uncertain.

The overall result of these events and conditions could lead to a prolonged period of volatile prices for oil and other petroleum products. Price volatility could result in reduced utilization and/or the suspension of operations at certain of the Company's facilities, buyers of the Company's products declaring force majeure and disruptions of pipeline and other transportation systems for the Company's products, which would further negatively impact Tamarack's production, and could adversely impact Tamarack's business, financial condition and results of operations.

(b) Inflation Risk

The general rate of inflation in Canada and many other countries saw a significant increase during 2022 and continuing into 2023, with some regions experiencing multi-decade highs. These increases reflect imbalances between supply and demand recoveries from the pandemic. The underlying factors include, but are not limited to, global supply chain disruptions, shipping bottlenecks, labor market constraints, geopolitical instability, and side effects from monetary and fiscal expansions. The global economic recovery remains uncertain. Prices for services and materials continue to evolve in response to fast-changing commodity markets, industry activities, supply chain dynamics, and government policies impacting operating and capital costs. Tamarack closely monitors market trends and works to mitigate cost impacts in all price environments through its economies of scale in procurement, efficient project management practices, and general productivity improvements.

The global economic recovery and rising inflationary trends are widely expected to result in rising interest rates. The ongoing invasion of Ukraine is another factor that could influence inflation or other parts of the Canadian and global economy. Since March 2, 2022, the Bank of Canada has begun to raise its benchmark interest rates for the first time since 2018. Further interest rate increases are possible over the next 12 months.

(c) Environmental and Climate Change Risk

As a result of growing international concern in respect of climate change, Tamarack has seen a significant increase in focus on the transition to alternative, lower-carbon energy sources. Governments, financial institutions, insurance companies, environmental and governance organizations, institutional investors, social and environmental activists, and individuals, are increasingly seeking to develop and implement, among other things, regulatory and policy changes, changes in investment strategies and habits, and a restructuring of energy consumption profiles, which, individually and collectively are intended to or have the effect of accelerating the transition to less carbon-intensive energy sources and the reduction in global consumption of fossil fuels. Overall, Tamarack is not able to estimate at this time the degree to which climate change related consumer behaviour, regulatory, climatic conditions, and climate-related transition risks could impact the Company's business, financial condition and results of operations.

Climate change may have actual or perceived adverse impacts on the Company's operations, business, and financial results, including an increase in the frequency of extreme climatic conditions. Weather and climate affect demand for crude oil and gas, and therefore, the predictability of weather and climate affects the Company's ability to accurately forecast supply and demand. In addition, the Company's operations, including exploration, production and construction operations, and the operations of major customers, suppliers and service providers, can be affected by acute and chronic physical climate risks, such as floods, forest fires, earthquakes, hurricanes,

landslides, mudslides, and other extreme weather events, natural disasters or long-term shifts in weather patterns. This may result in cessation or diminishment of production, delay of exploration and development activities or delay in executing the Company's capital expenditure plans, which may require the Company to adopt increased or additional mitigation requirements.

Growing concerns over climate change have also led to an increase in climate and environment-centric disputes and litigation in various jurisdictions, including at a Federal and Provincial level, alleging various claims and registering complaints, including that energy producers contribute to climate change, that such entities are not reasonably managing business risks associated with climate change, and that such entities have not adequately disclosed business risks of climate change. While many such climate change related actions are in preliminary stages of litigation, and in some cases raise novel or untested issues and causes of action, the risk that legal, societal, scientific and political developments will increase the likelihood of successful climate change related litigation against energy producers remains uncertain. The outcome and ramifications of any such litigation is uncertain and may materially impact the Company's business, financial condition or results of operations. The Company may also be subject to negative or damaging publicity associated with such matters, which may adversely affect the public sentiment and the Company's reputation, regardless of whether the Company is ultimately found responsible for claims alleged. We may be required to incur significant expenses or devote significant resources in defense against any such litigation.

Financial Risks

Financial risks include commodity pricing, exchange and interest rates and volatile markets.

Commodity price fluctuations result from market forces completely out of the Company's control and can significantly affect the Company's financial results. In addition, fluctuations between the Canadian dollar and the US dollar can also have a significant impact. Expenses are all incurred in Canadian dollars while oil, and to some extent natural gas, prices are based on reference prices denominated in US dollars. Due to both of these factors, Tamarack may enter into derivative instruments to partially mitigate the effects of downward price and foreign exchange volatility. To evaluate the need for hedging, management, with direction from the Board of Directors, monitors future pricing trends together with the cash flow necessary to fulfill capital expenditure requirements. Tamarack will only enter into a hedge to reduce downside uncertainty of pricing, not as a speculative venture.

Operational 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, existing reserves and their subsequent production will decline over time as they 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, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by Tamarack.

Tamarack endeavors to mitigate these risks by, among other things, ensuring that its employees are highly qualified and motivated. Prior to initiating capital projects, the Tamarack technical team completes an economic analysis, which attempts to reflect the risks involved in successfully completing the project. In an effort to mitigate the risk of not finding new reserves, or of finding reserves that are not economically viable, Tamarack utilizes various technical tools, such as 2D and 3D seismic data, rock sample analysis and the latest drilling and completions technology.

Insurance is in place to protect against major asset destruction or business interruptions, and includes, but is not limited to, events such as well blow-outs or pollution. In addition, Tamarack cultivates relationships with its suppliers in an effort to ensure good service regardless of the prevailing cycle of oil and gas activity.

Operational risk is mitigated by having Tamarack employees address the continued development of a new or established reservoir on a go-forward basis, using the same procedure that is used to address exploration risk. The decision to produce reserves is made based on the amount of capital required, production practices and reservoir quality. Tamarack evaluates reservoir development based on the timing, amount of additional capital required and the expected change in production values. Finding and development costs are controlled when capital is employed in a cost-effective manner.

Regulatory Risks

Regulatory risks include the possibility of changes to royalty, tax, environmental, safety, and public disclosure and reporting legislation. Tamarack endeavours to anticipate the costs related to compliance and budget sensibly for them. Changes to environmental and safety legislation may also cause delays to Tamarack's drilling plans, its production efficiencies and may adversely affect its future earnings. The Company's exploration and production activities emit GHG which may require Tamarack to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on Tamarack's business, financial condition, results of operations and prospects. Restrictive new legislation is a risk the Company cannot control.

The ISSB is expected to develop globally consistent, comparable and reliable standards for disclosing and reporting ESG and climate-related metrics. On March 31, 2022, the ISSB issued exposure drafts *IFRS S1 "General Requirements for Disclosure of Sustainability-related Financial Information"* and *IFRS S2 "Climate-related Disclosures"*. The Company is not able at this time to determine the impact on future financial statements or the cost of adopting any future standards that may result from these exposure drafts until a ballot is completed and the standards ratified. In addition, the Canadian Securities Administrators have issued a proposed NI 51-107 *Disclosure of Climate-related Matters*. The cost to implement and comply with these standards, and others, that may be developed or evolved over time, has not yet been quantified.

Forward-Looking Statements

Certain statements contained within this MD&A constitute forward-looking statements within the meaning of applicable Canadian securities legislation. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "anticipate", "budget", "plan", "endeavour", "continue", "estimate", "evaluate", "expect", "forecast", "monitor", "may", "will", "can", "able", "potential", "target", "intend", "consider", "focus", "identify", "use", "utilize", "manage", "maintain", "remain", "result", "cultivate", "could", "should", "believe", "strive" and similar expressions or the negative of such terms or other comparable terminology. The Company believes that the expectations reflected in such forward-looking statements are reasonable, but no assurance can be given that such expectations will prove to be correct and such forward-looking statements should not be unduly relied upon.

Without limitation, this MD&A contains forward-looking statements pertaining to:

- the intentions of management and the Company;
- the Company's commitment to maintaining financial flexibility and liquidity;
- the Company's business strategy, objectives, strength and focus, including with respect to acquisitions;
- the completion and implementation of the Nipisi methane gas conservation project and the objectives thereof;
- the impacts on the Company of the military conflict between Russia and Ukraine;

- the Company's commitment to advancing ESG practices, managing GHG emissions and to continued Indigenous and community partnerships in the areas where it operates;
- the Company's continued consideration of the impact of climate change and possible upcoming related financial and operational challenges and implications with respect to the future of the Company;
- the Company's continued consideration of the potential impacts of the evolving global demand for carbon-based energy and global advancement of alternative energy sources;
- the potential impact of ESG disclosure and reporting policies and standards imposed by the ISSB and proposed NI 51-107 and timing thereof including the expectation that the ISSB will issue the IFRS sustainability disclosure standards around the end of Q2 2023;
- expectations regarding the estimated recoverable amount of the Company's oil and natural gas properties, royalty rates as a percentage of revenue, and committed capital spending to develop the GORR Nipisi/Clearwater and Grande Prairie lands and timing thereof;
- expectations relating to future realized commodity prices, volatile commodity prices, royalty rates and oil price differentials and the effects thereof, including with respect to revenue, earnings and stability to oil pricing;
- the Company's financial and physical hedging program, including the use of financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates, and interest rates, and the effects thereof on cash flow risk and commodity pricing upside;
- purchases under the NCIB;
- expectations surrounding the benefits of the Deltastream assets including that such assets will continue to deliver results at or above forecast at the time of acquisition including in relation to the additional upside and potential capital efficiency improvements identified in respect of the same;
- the Company's plans in respect of returns of capital, including dividend and enhanced return programs;
- the Company's expectations surrounding its 2023 capital program and funding thereof, including in relation to the ability to satisfy its 2023 development capital program, dividend payments for the 2023 fiscal year and DAP Notes and Term Facility amortization payments required in 2023 by available credit facilities combined with anticipated adjusted funds flow;
- the amount of 2023 capital being directed towards both waterflood and infrastructure initiatives to set up lower sustaining capital and operating cost requirements throughout the Company's five-year plan;
- the impact of Tamarack's disposition of certain non-core natural gas assets and decommissioning obligations and the unplanned first quarter downtime on the Company's 2023 production range;
- the application of the terms of the Term Facility in respect of payments required thereunder and the timing thereof, including the minimum required payment Q1 2023;
- financial covenants applicable to the Syndicated Facility and Term Facility and the effect of outstanding Term Facility and DAP Notes (or lack thereof) in respect of the same;
- the maintained constructiveness of management's outlook with respect to WCS pricing despite persistent volatility;
- the expectation that additional refinery capacity additions will be brought on-line through the back half of 2023, creating additional competition for WCS barrels in the Gulf Coast;
- timing and impact of the TMX pipeline expansion (including pertaining to egress optionality for WCS barrels);
- the Company's intention to bring new facilities on-line in the second half of 2023 and corresponding effects thereof on Tamarack's 2023 production expense including in combination with the Company's realization of further synergies across Clearwater assets in the Nipisi and Marten Hills area;
- the Company's commitment to ESG principles and Indigenous relationships, including as disclosed in its 2022 Sustainability Report;
- the availability, size, terms, use and renewal of the SLL Facility, including the various lending vehicles used by the Company from time to time, and the terms thereof;

- the Company's ability to meet its obligations and commitments under the SL Notes;
- expectations relating to cash tax, tax pools, and deferred tax assets, including in respect of deferred income tax;
- the Company's head office sublease, as amended or extended, and the terms thereof;
- contractual obligations and commitments;
- estimates used to calculate decommissioning obligations and depletion of PP&E;
- the Company's risk management activities;
- the Company's plans in respect to its employees including for its employees to address the continued development of new or established reservoirs on a go-forward basis using the same procedure as is used to address exploration risk and the effects thereof on mitigation of operation risk;
- the Company expectation that its operating costs and transport costs will be driven lower throughout 2023 (including as a result of the Company's major infrastructure projects);
- expectations surrounding the timing of the Company's major infrastructure projects, including that the Wembley gas plant will be on-stream by the end of the second quarter and that the Clearwater Nipisi Pipeline and Terminal project will be on-line in the third quarter of 2023;
- the Company's continued execution of its Clearwater development program following having established control over the Deltastream assets and continued realization of operational and capital synergies in respect to the same;
- anticipated benefits of the Company's major infrastructure projects, including the expectation that the Wembley gas plant will reduce the Company's operating costs and cause improvements to the Company's level of control of processing of its sweet gas volumes associated with the Charlie Lake oil development and that the Clearwater Nipisi Pipeline and Terminal project will drive operating cost savings and netback enhancement from blending; the Company's capital budget and associated plans including the intention to remain within the lower half of its \$425 million to \$475 million budget range and maintain focus on maximizing free funds flow for debt repayment and enhancing shareholder returns as debt thresholds are met;
- expectations surrounding management's continued flexibility in respect of its second half capital program (including in relation to fluctuating commodity prices and management's monitoring thereof);
- expectations regarding the likelihood that identified changes to the Company's DCP and its ICFR during Q1 2023 will materially affect the Company's internal controls over financial reporting;
- expectations regarding the merits and the outcome of ongoing litigation; and
- the Company's expectations regarding inflation and interest rates and the ability to manage such pressures.

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

- future commodity prices, price differentials and the actual prices received for the Company's products;
- expected net production expenses and transportation expenses;
- estimated proved and probable oil and natural gas reserves;
- the effects of heavy volume apportionment and fluctuating diluent costs on the heavy oil market in Alberta;
- the ability to obtain equipment and services in the field in a timely and efficient manner;
- the ability to add production and reserves through acquisition and/or drilling at competitive prices;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the realization of anticipated benefits of acquisitions, including the acquisitions and the related drilling programs;
- the ability to explore and realize benefits from exposure to diversified gas markets;
- drilling results, including field production rates and decline rates;
- the performance of the waterflood projects;

- the continued application of horizontal drilling and fracturing techniques and pad drilling;
- the continued availability of capital and skilled personnel;
- the ability to obtain financing on acceptable terms;
- the accuracy of Tamarack’s geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation;
- the impact of increasing competition;
- the ability of the Company to secure adequate product transportation;
- the ability to enter into future commodity derivative contracts on acceptable terms;
- the continuation of the current tax, royalty and regulatory regime;
- the volatility in commodity prices and oil price differentials and the resulting effect on Tamarack’s revenue, cash provided by operating activities, adjusted funds flows and earnings;
- the actions of OPEC and non-OPEC oil and gas exporting countries to set production levels and the influence thereof on oil prices and global demand including in respect of recent cuts to the group’s production quotas (as announced by OPEC+ in April 2023);
- the ability to adjust capital spending relative to commodity prices and use financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates;
- Tamarack’s ability to maintain financial flexibility; and
- the impact of inflation on costs and interest rates.

Without limitations of the foregoing, future dividend payments, if any, and the level thereof, are uncertain, as the Company’s dividend policy and the funds available for the payment of dividends from time to time is dependent upon, among other things, commodity prices, free funds flow, financial requirements for the Company’s operations and the execution of its growth strategy, fluctuations in working capital and the timing and amount of capital expenditures, debt service requirements and other factors beyond the Company’s control. Further, the ability of Tamarack to pay dividends, and the frequency thereof, will be subject to applicable laws (including the satisfaction of the solvency test contained in applicable corporate legislation) and contractual restrictions contained in the instruments governing its indebtedness, including its credit facility.

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

- the material uncertainties and risks described under the headings “Unit Cost Calculation”, “Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures”, “Critical Accounting Estimates”, “Disclosure Controls and Internal Controls over Financial Reporting”, “Business Risks”, “Financial Risks”, “Operational Risks” and “Regulatory Risks”;
- the material assumptions and observations described under the headings “First Quarter in Review”, “Annual Guidance”, “Production”, “Petroleum and Natural Gas Sales”, “Risk Management”, “Royalties”, “Net Production Expenses”, “Transportation Expense”, “Blending Expense”, “Operating Netback”, “General and Administrative (“G&A”) Expenses”, “Stock-Based Compensation Expense”, “Finance Expense”, “Depletion, Depreciation and Amortization (“DD&A”)”, “Impairment (Impairment Reversal) of Property, Plant and Equipment and Exploration and Evaluation Assets”, “Current Income Tax (Asset) Liability”, “Adjusted Funds Flow and Net Income”, “Capital Expenditures (Including Exploration and Evaluation Expenditures)”, “Share Capital”, “Liquidity and Capital Resources”, “Debt”, “Commitments”, “Climate Change and Sustainability”, “Contingency” and “Selected Quarterly Information”;
- the risks relating to the Alberta wildfires, including in respect to safety, asset integrity, shutting in production, impact on production, maintaining 2023 guidance and resumption of operations;

- the risks with respect to unplanned third-party pipeline outages;
- the risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production and including continued weakness and volatility in commodity prices and petroleum product prices;
- the actions of OPEC and non-OPEC oil and gas exporting countries to set production levels and the influence thereof on oil prices and global demand;
- delays or changes in plans with respect to exploration or development projects or capital expenditures;
- volatility in market prices for oil and natural gas;
- uncertainties associated with estimating proved and probable oil and natural gas reserves and the ability of the Company to realize value from its properties;
- geological, technical, drilling and processing problems;
- facility and pipeline capacity constraints and access to processing facilities and to markets for production;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- credit worthiness of counterparties to commodity, foreign exchange and interest rate contracts;
- increased borrowing costs due to increased lending rates from prime rate increase, negative changes to financial metrics evaluated under SLL Facility and SL Notes sustainability performance targets and/or decreased ESG performance as determined by a third-party rating agency;
- the evolving impact of the COVID-19 pandemic on the Company's business, financial condition and results of operations;
- uncertainty regarding the full impact of COVID-19 on global economies and oil demand and commodity prices, including the effects of recent outbreaks of COVID-19 in China;
- marketing and transportation;
- prevailing weather and break-up conditions;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- net production costs, transportation costs and future development costs;
- the ability to access sufficient capital from internal and external sources;
- changes in tax, royalty and environmental legislation and any government policy;
- any legal proceedings, the results thereof and the impact on the Company's business, financial condition and results of operations;
- third party inability to manage inflationary cost pressures;
- changes in the political landscape, both domestically and abroad; and
- increased operating and capital costs due to inflationary pressures (actual and anticipated).

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

Information Form for the year ended December 31, 2022, which may be accessed on Tamarack's SEDAR profile www.sedar.com or on the Company's website at www.tamarackvalley.ca.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Tamarack's 2023 development capital program and plans regarding payment of 2023 dividends as well as DAP Notes and Term Facility amortization by using available credit facilities combined with anticipated adjusted funds flow, Tamarack's 2023 guidance related to expected capital expenditures, production, annual average production, average oil & NGL weighting and expenses and leasing expenditures, prospective results of operations, production, adjusted funds flow, free funds flow, net debt, net debt to annualized adjusted funds flow, balance sheet strength, the Company's 2023 budget and associated targets, debt repayments, total returns and components thereof, decline rates, royalty rates and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs and the assumptions outlined under "Non-IFRS Financial Measures, Non-IFRS Financial Ratios and Capital Management Measures", and should not be used for purposes other than those for which it is disclosed herein. Tamarack and its management believe that the prospective financial information has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represent, to the best of management's knowledge and opinion, Tamarack's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future activities or results.

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

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets

(unaudited)(thousands)

	March 31, 2023	December 31, 2022
Assets		
Current assets:		
Accounts receivable (note 5)	\$151,289	\$177,218
Prepaid expenses and deposits	10,080	6,842
Current income tax (note 9)	2,292	–
Fair value of financial instruments (note 3)	1,440	–
	165,101	184,060
Note receivable	20,000	20,000
Fair value of financial instruments (note 3)	172	254
Property, plant and equipment (note 6)	4,366,847	4,370,025
Exploration and evaluation assets (note 7)	41,640	45,362
	\$4,593,760	\$4,619,701
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	\$240,488	\$220,568
Debt (note 11)	286,667	265,000
Other liabilities (note 12 and 17)	9,996	6,424
Lease liabilities	4,171	4,479
Decommissioning obligations (note 8)	11,144	11,200
Cross-currency swap (note 11)	8,995	753
Current income tax (note 9)	–	123,924
Fair value of financial instruments (note 3)	14,301	10,594
	575,762	642,942
Debt (note 11)	1,000,051	930,206
Other liabilities (note 12 and 17)	25,208	25,746
Lease liabilities	5,581	6,360
Decommissioning obligations (note 8)	254,230	253,788
Deferred tax liability	585,322	597,420
	2,446,154	2,456,462
Shareholders' equity:		
Share capital (note 14)	1,879,250	1,879,250
Treasury shares (note 14)	(687)	(2,451)
Contributed surplus	28,438	27,475
Retained earnings	240,605	258,965
	2,147,606	2,163,239
Subsequent events (note 3, 6, 11 and 14)		
Commitments (note 18)		
Contingency (note 19)		
	\$4,593,760	\$4,619,701

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Income and Comprehensive Income
For the three months ended March 31, 2023 and 2022
(unaudited) (thousands, except per share amounts)

	2023	2022
Revenue:		
Oil and natural gas (note 5)	\$378,546	\$298,254
Processing and other income (note 5)	1,501	641
Royalties	(73,292)	(58,483)
Net revenue	306,755	240,412
Financial instrument contracts:		
Realized loss on financial instruments (note 3)	(6,504)	(14,867)
Unrealized loss on financial instruments (note 3)	(2,349)	(56,597)
Net revenue and losses on financial instruments	297,902	168,948
Expenses:		
Production	65,040	38,286
Transportation	23,838	7,246
Blending	1,826	–
General and administration	7,799	8,490
Stock-based compensation (note 16)	2,786	1,532
Finance (note 13)	27,785	8,547
Depletion, depreciation and amortization (note 6 and 7)	158,306	69,202
Site rehabilitation program grant (note 8 and 17)	(174)	(129)
	287,206	133,174
Income before taxes	10,696	35,774
Taxes:		
Current income tax expense (note 9)	(20,289)	(17,722)
Deferred income tax recovery	12,098	8,405
	(8,191)	(9,317)
Net income and comprehensive income	\$2,505	\$26,457
Net income per share (note 15):		
Basic	–	\$ 0.06
Diluted	–	\$ 0.06

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Changes in Shareholders' Equity
(unaudited)(thousands)

	Number of common shares, net of treasury shares	Share capital	Treasury shares	Contributed surplus	Retained earnings (deficit)	Total Shareholders' equity
Balance at January 1, 2022	406,938	\$1,242,392	\$(3,336)	\$48,311	\$(26,742)	\$1,260,625
Issue of common shares	26,298	129,388	–	–	–	129,388
Purchase of common shares for Option, RSU and PSU exercise	(2,520)	–	(12,354)	–	–	(12,354)
Option, RSU and PSU exercise	2,110	–	9,494	(9,494)	–	–
Change to SBC liability	–	–	–	(14,685)	–	(14,685)
Option exercise proceeds	–	–	1,523	–	–	1,523
Return of common shares to treasury	–	(2,646)	2,078	568	–	–
Stock-based compensation	–	–	–	2,645	–	2,645
Dividends	–	–	–	–	(10,579)	(10,579)
Net income	–	–	–	–	26,457	26,457
Balance at March 31, 2022	432,826	\$1,369,134	\$(2,595)	\$27,345	\$(10,864)	\$1,383,020
Balance at January 1, 2023	556,441	\$1,879,250	\$(2,451)	\$27,475	\$258,965	\$2,163,239
Option, RSU and PSU exercise	360	–	1,441	(1,441)	–	–
Stock-based compensation	–	–	–	2,404	–	2,404
Option exercise proceeds	–	–	323	–	–	323
Dividends	–	–	–	–	(20,865)	(20,865)
Net income	–	–	–	–	2,505	2,505
Balance at March 31, 2023	556,801	\$1,879,250	\$(687)	\$28,438	\$240,605	\$2,147,606

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three months ended March 31, 2023 and 2022
(unaudited)(thousands)

	2023	2022
Cash provided by (used in):		
Operating:		
Net income	\$2,505	\$26,457
Depletion, depreciation and amortization (note 6 and 7)	158,306	69,202
Stock-based compensation (note 16)	2,786	1,532
Site rehabilitation program grant (note 8 and 17)	(174)	(129)
Finance (note 13)	27,785	8,547
Interest paid	(16,268)	(4,942)
Unrealized loss on financial instruments (note 3)	2,349	56,597
Income tax expense	8,191	9,317
Income tax paid (note 9)	(146,505)	
Decommissioning expenditures (note 8)	(875)	(437)
Changes in non-cash working capital (note 10)	21,524	(33,291)
Cash provided by operating activities	59,624	132,853
Financing:		
Change in SLL Facility (note 11)	148,766	(146,010)
Issuance of SL Notes, net (note 11)	–	195,096
Repayment of DAP Notes (note 11)	(50,000)	–
Purchase of common shares for Option, RSU and PSU exercises (note 14)	–	(12,354)
Proceeds from option exercises (note 16)	323	1,523
Repayment of lease liabilities	(1,087)	(921)
Dividends (note 14)	(20,867)	(10,579)
Changes in other liabilities (note 12 and 17)	995	2,608
Changes in non-cash working capital (note 10)	(19)	4,700
Cash provided by financing activities	78,111	34,063
Investing:		
Property, plant and equipment additions (note 6)	(145,642)	(111,783)
Government assistance	611	4,442
Exploration and evaluation additions (note 7)	(3,131)	(18,026)
Acquisitions (note 6)	(2,939)	(94,663)
Proceeds from dispositions (note 6)	180	–
Changes in non-cash working capital (note 10)	13,186	53,114
Cash used in investing activities	(137,735)	(166,916)
Change in cash and cash equivalents	–	–
Cash and cash equivalents, beginning of period	–	–
Cash and cash equivalents, end of period	\$ –	\$ –

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three months ended March 31, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

1. Reporting entity:

Tamarack Valley Energy Ltd. (“Tamarack” or the “Company”) is a corporation existing under the laws of Alberta. The Company is engaged in the exploration for, development and production of, oil and natural gas. The consolidated financial statements of Tamarack consist of the Company and its wholly owned subsidiary, which is incorporated in the United States: Tamarack Ridge Resources Inc. No assets are held within Tamarack Ridge Resources Inc. Tamarack is a publicly traded company, incorporated and domiciled in Canada. The address of its registered office is Suite 4300, 888 – 3rd Street S.W., Calgary, Alberta, T2P 5C5. The address of its head office is currently Suite 3300, 308 – 4th Avenue S.W., Calgary, Alberta, T2P 0H7.

2. Basis of preparation:

(a) Statement of compliance:

The condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standard 34, “Interim Financial Reporting” of International Financial Reporting Standards (“IFRS”).

These condensed consolidated interim financial statements have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company for the year ended December 31, 2022. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These condensed consolidated interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company’s annual filings for the year ended December 31, 2022. Certain prior period balances were reclassified to conform to current period presentation.

The condensed consolidated interim financial statements have been prepared on the historical cost basis except for certain derivative financial instruments (including cross-currency swaps) and share-based payment arrangements classified as cash-settled which are measured at fair value and share based payment arrangements classified as equity are measured at fair value at the grant date in accordance with IFRS 2.

These condensed consolidated interim financial statements are presented in Canadian dollars, which is the Company’s functional currency. Tamarack Ridge Resources Inc. has a United States dollar functional currency.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on May 10, 2023.

(b) Estimates and judgments:

The preparation of the condensed consolidated interim financial statements in conformity with IFRS requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities as at the date of the condensed consolidated interim financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the condensed consolidated interim financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. The significant estimates and judgments made by management in the preparation of these condensed consolidated interim financial statements were consistent with those applied to the annual consolidated financial statements as at and for the year ended December 31, 2022.

TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three months ended March 31, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

3. Financial instruments and risk management:

(a) Financial instruments:

The Company's financial assets and liabilities are comprised of Accounts receivable, Note receivable, Accounts payables and accrued liabilities, Current income tax, Fair value of financial instruments, Cross-currency swap, Other liabilities (includes Cash award incentive plan liability, Government loan liability, and Facilities acquisition payments), and Debt. The carrying value of the Note receivable, and Debt approximates their fair value as they bear interest at market rates. Except for the Fair value of financial instruments, Cross-currency swap and the Cash award incentive plan liability, which are recorded at fair value through profit or loss, carrying values reflect the current fair value of the Company's financial instruments.

A number of the Company's accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods outlined below. The Company's fair value measurements are classified as one of the following levels of the fair value hierarchy:

Level 1 – inputs represent unadjusted quoted prices in active markets for identical assets and liabilities. An active market is characterized by a high volume of transactions that provides pricing information on an ongoing basis.

Level 2 – inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These valuations are based on inputs that can be observed or corroborated in the marketplace, such as market interest rates or forward prices for commodities.

Level 3 – inputs for the asset or liability are not based on observable market data.

The Company aims to maximize the use of observable inputs when preparing calculations of fair value. Classification of each measurement into the fair value hierarchy is based on the lowest level of input that is significant to the fair value calculation. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

(b) Financial derivatives:

It is the Company's policy to economically hedge some oil and natural gas sales, foreign exchange rates and interest rates using various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts. The Company's production is usually sold using "spot" or near-term contracts, with prices fixed at the time of transfer of custody or based on a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering long-term, fixed price marketing contracts. The Company does not enter commodity contracts other than to meet its expected sales requirements. The Company manages risk for these contracts by engaging with a variety of counterparties, all of which are investment-grade banking institutions or large purchasers of commodities. All counterparties have been assessed for credit worthiness.

TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three months ended March 31, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

All financial derivative contracts are measured and recognized as fair value through profit and loss and are recorded on the balance sheet at fair value. The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted amounts and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use level 2 inputs, being published information with respect to volatility, prices, and interest rates. Derivatives are recorded on the balance sheet at fair value with the change in fair value being recognized as an unrealized gain or loss in profit or loss. Cross-currency swaps are recorded on the balance sheet at fair value with the change in fair value being recognized as a finance expense.

At March 31, 2023, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the following tables.

West Texas Intermediate and Differential Crude Oil Derivatives:

	Q2 2023		Q3 2023		Q4 2023	
WTI Put						
Volume (bbls/d)	2,000		-		-	
Average Put/Premium (USD/bbl)	55.00	2.90	-	-	-	-
WTI 2-way Collar						
Volume (bbls/d)	30,500		24,250		7,500	
Average Put/Call/Premium (USD/bbl)	69.42	103.80	2.84	67.67	98.23	2.96
Volume (bbls/d)	1,050		850		850	
Average Put/Call/Premium (CAD/bbl)	82.90	110.94	-	80.44	108.64	-
WTI Fixed Price						
Volume (bbls/d)	300		200		200	
Average Fixed Price (CAD/bbl)	94.23		91.75		91.75	
Mixed Sweet Blend Differential (MSW)						
Volume (bbls/d)	5,000		2,000		1,000	
Average Fixed Price (USD/bbl)	(2.92)		(2.80)		(2.70)	
Western Canadian Select Differential (WCS)						
Volume (bbls/d)	12,000		7,000		4,000	
Average Fixed Price (USD/bbl)	(20.48)		(16.11)		(17.94)	
Volume (bbls/d)	1,000		700		700	
Average Fixed Price (CAD/bbl)	(18.66)		(19.29)		(19.29)	

Natural Gas Derivatives:

	Summer 23 ⁽¹⁾	
AECO – NYMEX Basis		
Volume (mmbtu/d)	17,500	
Average Fixed Price (USD/mmbtu)	(1.87)	
NYMEX Collar		
Volume (mmbtu/d)	17,500	
Average Put/Call (USD/mmbtu)	4.56	6.98

⁽¹⁾ Summer runs from April 1 to October 31 of the given year.

TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three months ended March 31, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

Foreign Exchange Derivatives:

	Q2 2023			Q3 2023			Q4 2023			Q1 2024		
CAD/USD Put												
Amount (USD/month)	\$3,000,000			-	-	-	-	-	-	-	-	-
Average Put/Premium (CAD/USD)	1.3375	0.0100		-	-		-	-		-	-	
CAD/USD Collar												
Amount (USD/month)	\$10,000,000			\$12,000,000			\$12,000,000			-		
Average Put/Call (CAD/USD)	1.3205	1.3888		1.3254	1.3909		1.3254	1.3909		-	-	
CAD/USD Variable Rate Collar												
Amount (USD/month)	\$9,000,000			\$11,500,000			\$11,500,000			\$8,500,000		
Average Put/Call/Knockout Rate (CAD/USD) ⁽¹⁾	1.33	1.42	1.37	1.33	1.41	1.36	1.33	1.41	1.36	1.33	1.41	1.36
CAD/USD Variable Rate Collar (Extendable Option)⁽²⁾												
Amount (USD/month)	\$10,000,000			\$12,500,000			\$12,500,000			\$4,500,000		
Average Put/Call/Knockout Rate (CAD/USD) ⁽¹⁾	1.33	1.40	1.37	1.33	1.40	1.36	1.33	1.40	1.36	1.33	1.41	1.37
CAD/USD Swap												
Amount (USD/month)	\$5,000,000			\$6,000,000			\$6,000,000			\$1,000,000		
Average Fixed Price (CAD/USD)	1.3413			1.3399			1.3399			1.3600		

	Q2 2024			Q3 2024			Q4 2024		
CAD/USD Variable Rate Collar									
Amount (USD/month)	\$8,500,000			\$2,000,000			\$2,000,000		
Average Put/Call/Knockout Rate (CAD/USD)	1.33	1.41	1.36	1.34	1.42	1.36	1.34	1.42	1.36
CAD/USD Variable Rate Collar (Extendable Option)									
Amount (USD/month)	\$4,500,000			\$2,000,000			\$2,000,000		
Average Put/Call/Knockout Rate (CAD/USD)	1.33	1.41	1.37	1.32	1.40	1.38	1.32	1.40	1.38
CAD/USD Swap									
Amount (USD/month)	\$1,000,000			-			-		
Average Fixed Price (CAD/USD)	1.3600			-			-		

⁽¹⁾ If the average rate for the month exceeds the call, Tamarack receives an average rate forward equivalent to the knockout rate.

⁽²⁾ Includes an extension option at the end of the collar, at the counterparty's option, for an equivalent term at an average rate forward fixed price equal to the call. If all extension options were exercised, Tamarack would hold additional average rate forward contracts as follows: H1/24 - \$10.0 million at 1.3975; H2/24 - \$15.0 million at 1.4017; H1/25 - \$2.0 million at 1.4000; H2/25 - \$2.0 million at 1.4000.

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Interest Rate Derivatives:

	2023	2024
CDOR Swap		
Amount (million CAD\$/year)	34.3	6.4
Average Interest Rate	1.191%	1.043%

At March 31, 2023, Tamarack's derivative commodity, foreign exchange and interest rate contracts were fair valued with a net liability value of \$12,689 (December 31, 2022 - \$10,340 net liability) recorded on the balance sheet. The Company had an unrealized loss of \$2,349 and a realized loss of \$6,504 recorded in earnings for the three months ended March 31, 2023 (March 31, 2022 - \$56,597 unrealized loss and \$14,867 realized loss).

Subsequent to March 31, 2023, the Company has entered into the financial contracts noted in the table below.

West Texas Intermediate and Differential Crude Oil Derivatives

	Q3 2023			Q4 2023			Q1 2024			Q2 2024		
WTI 2-way Collar												
Volume (bbls/d)	-	-	-	2,000			-	-	-	-	-	-
Average Put/Call/Premium (USD/bbl)	-	-	-	67.00	95.35	2.00	-	-	-	-	-	-
Western Canadian Select Differential (WCS)												
Volume (bbls/d)	6,000			3,500			1,000			1,500		
Average Fixed Price (USD/bbl)	(14.49)			(16.19)			(14.25)			(14.13)		

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement, the realized benefit or loss is recognized in oil and natural gas revenue.

At March 31, 2023, the Company held the following physical commodity contracts:

	Q2 2023
Mixed Sweet Blend Differential (MSW)	
Volume (bbls/d)	2,086
Average Fixed Price (USD/bbl)	(2.18)

Subsequent to March 31, 2023, the Company has not entered into any physical commodity contracts.

Assets and liabilities related to risk management contracts are offset, and the net amount presented in the balance sheet, when the Company has a legal right to offset the amounts and intends to settle them on a net basis or to realize the asset and settle the liability simultaneously.

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4. Capital management:

The Company's policy is to maintain a strong capital base to maintain investor, creditor and market confidence and to sustain future development of the business. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Company considers its capital structure to include Shareholders' equity, Note receivable, Debt, Other liabilities (excluding Cash award incentive plan) and working capital. In order to maintain or adjust the capital structure, the Company may issue shares, use debt and adjust its capital spending to manage current and projected debt levels.

(a) Adjusted funds flow:

Adjusted funds flow is calculated by taking cash flow from operating activities, deducting current income tax expense and interest expense excluding fees, adding back income tax paid, interest paid, expenditures on decommissioning obligations and transaction costs and deducting or adding back changes in non-cash working capital, as required. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow. Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt, pay dividends and fund future capital investment.

For the three months ended March 31,	2023	2022
Cash flow from operating activities	\$59,624	\$132,853
Current income tax expense (note 9)	(20,289)	–
Income tax paid (note 9)	146,505	–
Interest expense, excluding fees	(24,188)	–
Interest paid	16,268	–
Decommissioning expenditures	875	437
Changes in non-cash working capital	(21,524)	33,291
Adjusted funds flow	\$157,271	\$166,581

(b) Free funds flow and Capital expenditures:

Free funds flow is calculated by taking adjusted funds flow and subtracting capital expenditures, calculated as property, plant and equipment additions (net of government assistance) plus exploration and evaluation additions included in the Condensed Consolidated Interim Statement of Cash Flows.

For the three months ended March 31,	2023	2022
Adjusted funds flow	\$157,271	\$166,581
Less: Property, plant and equipment expenditures	145,642	111,783
Government assistance	(611)	(4,442)
Exploration and evaluation expenditures	3,131	18,026
Capital expenditures	148,162	125,367
Free funds flow	\$9,109	\$41,214

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(c) Net debt to annualized adjusted funds flow:

The Company monitors capital based on the ratio of net debt to annualized adjusted funds flow. This ratio is calculated as net debt, defined as working capital deficiency plus Debt plus Government loan liability plus Facilities acquisition payments, less Note receivable, divided by adjusted funds flow for the most recent calendar quarter and then annualized. Working capital deficiency is calculated as Accounts payable and accrued liabilities plus Current income tax liability plus Cross-currency swap liability minus Current income tax asset minus Accounts receivable minus Prepaid expenses and deposits minus Cross-currency swap asset.

The Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

As at March 31, 2023, the Company's ratio of net debt to annualized first quarter adjusted funds flow was 2.2 to 1 (December 31, 2022 – 1.7 to 1). The Company believes that available credit facilities combined with anticipated adjusted funds flow will be sufficient to satisfy Tamarack's development capital program, dividend payments and DAP Notes and Term Facility amortization payments for the next 12 months.

	March 31, 2023	December 31, 2022
Accounts payable and accrued liabilities	\$240,488	\$220,568
Current income tax (asset) liability	(2,292)	123,924
Cross currency swap liability	8,995	753
Accounts receivable	(151,289)	(177,218)
Prepaid expenses and deposits	(10,080)	(6,842)
Working capital deficiency	\$85,822	\$161,185
Note receivable	(20,000)	(20,000)
Credit facilities	791,663	650,848
SL Notes	288,388	287,691
DAP Notes	206,667	256,667
Government loan and Facilities acquisition payments	21,528	20,179
Net debt	\$1,374,068	\$1,356,570
Quarterly adjusted funds flow	\$157,271	\$196,746
Annualized factor	4	4
Annualized adjusted funds flow	\$629,084	\$786,984
Net debt to annualized adjusted funds flow	2.2x	1.7x

Neither the Company nor its subsidiary are subject to externally imposed capital requirements.

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5. Revenue:

The Company sells its production pursuant to fixed-price or variable-price contracts. The transaction price for variable-price contracts is based on a benchmark commodity price, adjusted for quality, location, or other factors whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver fixed or variable volumes of light oil, heavy oil, natural gas or NGL to the contract counterparty.

Revenue is recognized when the Company gives up control of the unit of production at the delivery point agreed to under the terms of the contract. The amount of revenue recognized is based on the agreed transaction price and the volumes delivered. Any variability in the transaction price relates specifically to Tamarack's efforts to transfer production and therefore the resulting revenue is allocated to the production volumes delivered in the period to which the variability relates. The Company does not have any factors considered to be constraining in the recognition of revenue with variable pricing factors. The Company's contracts with customers generally have a term of one year or less, except in the case of certain natural gas contracts, whereby delivery takes place throughout the contract period. As of March 31, 2023, the Company did not have any contracts for the sale of its future production beyond one year in term. Revenues are normally collected on the business day nearest the 25th day of the month following the sale.

The Company's revenues were primarily generated in its core areas: the Clearwater oil play in north-central Alberta; the Charlie Lake oil play in northwestern Alberta; the Cardium oil play in central Alberta and the Viking oil play in central and southern Alberta. The Company's customers are oil and natural gas marketers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by selling volumes to numerous oil and natural gas marketers under customary industry sale and payment terms.

The following table presents the Company's total revenues disaggregated by revenue source:

For the three months ended March 31,	2023	2022
Light oil	\$145,613	\$177,096
Heavy oil	192,519	63,926
Natural gas	23,382	36,423
Natural gas liquids	17,032	20,809
Oil and natural gas revenues	\$378,546	\$298,254
Processing income	909	641
Total revenue	\$379,455	\$298,895

Included in accounts receivable on March 31, 2023 was \$131.0 million (December 31, 2022 - \$130.8 million) of accrued production revenue. There were no significant adjustments for the prior period accrued production revenue reflected in the current period.

Included in Processing and other income for the three months ended March 31, 2023 is \$0.9 million of Processing income (March 31, 2022 - \$0.6 million) and accrued interest income at 12% per annum on the Note receivable of \$0.6 million (March 31, 2022 - \$nil).

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6. Property, plant and equipment:

	Oil and natural gas interests	Other assets	Total
Cost:			
Balance at December 31, 2021	\$3,391,539	\$5,615	\$3,397,154
Right-of-use assets	1,283	1,401	2,684
Acquisitions	2,200,479	377	2,200,856
Capital additions	406,203	1,137	407,340
Decommissioning costs	(19,557)	–	(19,557)
Stock-based compensation	3,739	–	3,739
Transfer from exploration and evaluation assets (note 7)	6,559	–	6,559
Disposals	(143,973)	–	(143,973)
Balance at December 31, 2022	5,846,272	8,530	5,854,802
Acquisitions	4,346	–	4,346
Capital additions	144,543	488	145,031
Decommissioning costs	(2,055)	–	(2,055)
Stock-based compensation	1,303	–	1,303
Transfer from exploration and evaluation assets (note 7)	6,084	–	6,084
Disposals	(350)	–	(350)
Balance at March 31, 2023	\$6,000,143	\$9,018	\$6,009,161
Accumulated depletion, depreciation and impairment:			
Balance at December 31, 2021	\$1,158,513	\$2,106	\$1,160,619
Depletion and depreciation	373,388	1,593	374,981
Disposals	(50,823)	–	(50,823)
Balance at December 31, 2022	1,481,078	3,699	1,484,777
Depletion and depreciation	157,143	394	157,537
Balance at March 31, 2023	\$1,638,221	\$4,093	\$1,642,314
Carrying amounts:			
At December 31, 2022	\$4,365,194	\$4,831	\$4,370,025
At March 31, 2023	\$4,361,922	\$4,925	\$4,366,847

(a) Security:

At March 31, 2023, all of the Company's properties were pledged as security for the credit facilities (note 11).

(b) Depletion and depreciation:

The calculation of depletion at March 31, 2023 includes estimated future development costs of \$1,570,780 (December 31, 2022 – \$1,589,050) associated with the development of the Company's proved and probable oil and natural gas reserves and excludes salvage value of \$100,923 (December 31, 2022 – \$99,420).

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(c) Impairment (reversal):

At March 31, 2023 and 2022 there were no indicators of impairment or reversal of impairment identified on any of the Company's CGUs within property, plant and equipment and no impairment or reversal of impairment tests were performed.

(d) Acquisitions and dispositions:

On January 6, 2023 the Company acquired assets in the Charlie Lake oil CGU for cash consideration of approximately \$2.9 million. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquisition being accounted for as an asset acquisition. As such the purchase price of the minor acquisition was allocated to the identifiable assets and liabilities based on their relative fair values at the date of the acquisition.

For the three months ended March 31, 2023 the Company disposed of a non-core property for proceeds of \$0.2 million. There was no gain or loss recorded on the disposition.

Subsequent to March 31, 2023 the Company disposed of certain non-core natural gas properties for proceeds of \$2.3 million.

(e) Right-of-use assets:

Certain field operations (processing facilities and equipment and surface leases) and office leases are included in property, plant and equipment as right-of-use assets:

	Field operations	Office leases	Total
Balance at December 31, 2021	\$8,041	\$1,700	\$9,741
Lease additions	1,283	1,401	2,684
Leases acquired	1,093	377	1,470
Depletion and depreciation	(2,765)	(1,002)	(3,767)
Balance at December 31, 2022	\$7,652	\$2,476	\$10,128
Depletion and depreciation	(804)	(234)	(1,038)
Balance at March 31, 2023	\$6,848	\$2,242	\$9,090

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7. Exploration and evaluation assets:

	Total
Cost:	
Balance at December 31, 2021	\$26,168
Additions	51,237
Disposal	(3,007)
Transfer to property, plant and equipment (note 6)	(6,559)
Balance at December 31, 2022	67,839
Additions	3,131
Transfer to property, plant and equipment (note 6)	(6,084)
Balance at March 31, 2023	\$64,886
Accumulated amortization and impairment:	
Balance at December 31, 2021	\$22,360
Amortization	2,702
Disposal	(2,585)
Balance at December 31, 2022	22,477
Amortization	769
Balance at March 31, 2023	\$23,246
Carrying amounts:	
At December 31, 2022	\$45,362
At March 31, 2023	\$41,640

Exploration and evaluation additions for the three months ended March 31, 2023 includes approximately \$3.1 million of drilling and completion costs in the Greater Peavine Clearwater area.

For the three months ended March 31, 2023 there were no indicators of impairment identified on any of the Company's CGUs within exploration and evaluation assets. In addition, there was no impairment recorded as a result of the impairment assessment on the transfer of exploration and evaluation assets to property, plant and equipment for the three months ended March 31, 2023.

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8. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted and uninflated amount of cash flows required to settle its decommissioning obligations to be approximately \$312.3 million at March 31, 2023 (December 31, 2022 – \$309.1 million), which is expected to be incurred between 2023 and 2050. A risk-free rate of 3.0% (December 31, 2022 – 3.3%) and an inflation rate of 1.7% (December 31, 2022 – 2.1%) have been used to calculate the present value of the decommissioning obligations at March 31, 2023 as presented in the table below:

	Three months ended March 31, 2023	Year ended December 31, 2022
Balance, beginning of the period	\$264,988	\$284,472
Liabilities incurred	2,157	7,701
Liabilities acquired	1,407	19,719
Change in estimates	(4,212)	(54,787)
Change in discount rate on acquisition	–	27,529
Expenditures	(875)	(7,976)
Site rehabilitation program grant (note 17)	(174)	(3,377)
Liabilities disposed	(170)	(15,969)
Accretion (note 13)	2,253	7,676
Balance, end of the period	\$265,374	\$264,988

During the three months ended March 31, 2023 approximately \$0.2 million was granted and paid through the SRP and ASCP programs to pay service companies to complete abandonment and reclamation work (December 31, 2022 – \$3.4 million).

The change in estimates for the three months ended March 31, 2023 resulted from decommissioning obligations being revalued using a risk-free rate of 3.0% and an inflation rate of 1.7% as opposed to a risk-free rate of 3.3% and an inflation rate of 2.1% used at December 31, 2022.

Timing of decommissioning obligation expenditures expected to be incurred are:

	As at March 31, 2023
Decommissioning obligations – Less than 1 year	\$11,144
Decommissioning obligations – Greater than 1 year	254,230
Total	\$265,374

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9. Current income tax (asset) liability:

	Three months ended March 31, 2023	Year ended December 31, 2022
Balance, beginning of the period	\$123,924	\$ –
Payments	(124,114)	–
Current income tax expense	20,289	75,849
Acquired income tax payable	–	48,075
Current income tax instalments	(22,391)	–
Balance, end of the period	\$(2,292)	\$123,924

10. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended March 31, 2023	2022
Source/(use) of cash:		
Accounts receivable	\$25,929	\$(51,527)
Prepaid expenses and deposits	(3,238)	(2,154)
Accounts payable and accrued liabilities	19,920	73,464
Interest payable	(7,922)	(2,026)
Dividends payable	2	3,600
Working capital acquired	–	3,166
	\$34,691	\$24,523
Related to operating activities	\$21,524	\$(33,291)
Related to financing activities	\$(19)	\$4,700
Related to investing activities	\$13,186	\$53,114

11. Debt:

	March 31, 2023	December 31, 2022
Current Debt		
Credit Facilities		
Term Facility	\$86,667	\$65,000
DAP Notes	200,000	200,000
	\$286,667	\$265,000
Long-term Debt		
Credit Facilities		
SLL Facility	\$556,663	\$415,848
Term Facility	148,333	170,000
Credit Facilities total	\$704,996	\$585,848
SL Notes	288,388	287,691
DAP Notes	6,667	56,667
	\$1,000,051	\$930,206
Total Debt	\$1,286,718	\$1,195,206

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(a) Credit Facilities:

On October 13, 2022 the Company established a new three-year covenant-based SLL Facility, replacing the existing SLL Facility. The SLL Facility increased to \$700.0 million and is paired with a \$260.0 million two-year secured amortizing term-loan (“Term Facility”) from a syndicate of lenders for a total lending capacity of \$960.0 million. The SLL Facility and the Term Facility collectively constitute a “Syndicated Facility”. The Syndicated Facility is secured by a \$2.0 billion debenture with fixed coverage over all the assets of the Company. The SLL portion of the facility bears interest at the applicable rate for the borrowing employed plus a credit margin based on the senior debt to EBITDA ratio of the Company.

As the Syndicated Facility is a covenant-based facility, it is not contingent on the reserve base of the Company and not subject to annual or semi-annual redeterminations. The Syndicated Facility may be reviewed for extension, of term or amount, once annually at the discretion of the borrower. There are no mandatory principal repayments required prior to maturity.

Subsequent to March 31, 2023 the Credit Facilities went through a review which resulted in an extension of the SLL Facility maturity date from October 2025 to May 2026 and an increase to \$875.0 million. Concurrently, the Term Facility was decreased to \$200.0 million for a total lending capacity of \$1,075.0 million.

SLL Facility:

The SLL Facility contains commercial covenants and sustainability adjustments in addition to financial covenants detailed below.

A total of \$556.7 million was drawn as of March 31, 2023 (December 31, 2022 – \$415.8 million). The average interest rate applicable to the drawn amounts as of this date was 6.88% (December 31, 2022 – 6.21%).

The Company manages its SLL Facility using a combination of prime rate loans, BA notes and US dollar denominated SOFR loans. Concurrent with the drawdown of US dollar SOFR loans, the Company may enter into cross-currency swaps (“CCS”) to fix the foreign exchange on US dollar SOFR loan amounts for purposes of interest and principal repayments. At March 31, 2023, the Company had drawn US\$425.0 million, fixed at notional amounts of \$583.4 million through CCS maturing across the month of April 2023 (December 31, 2022 – the Company had drawn US\$290.0 million, fixed at notional amounts of \$393.5 million through various CCS).

Term Facility:

The Term Facility is a covenant-based, non-revolving facility with a maturity date of October 13, 2024 and may be extended for a single twelve-month term at the request of the borrower and the discretion of the lenders. Minimum quarterly amortization payments of \$21.7 million commenced in Q1 2023. If the Company determines it has generated Excess Cash Flow as defined by the Syndicated Facility agreement, the minimum required payment for the quarter will be the greater of fifty percent (50%) of the determined Excess Cash Flow and the minimum amortization payment. The balance remaining after all quarterly payments over the two-year term of the Term Facility is due and payable at maturity. The Term Facility bears interest at the applicable rate for the borrowing employed plus a fixed margin rate. The Company made its Q1 2023 payment on December 30, 2022 of \$25.0 million in accordance with the agreement due to proceeds on disposition of a non-core property in December, which, as defined in the agreement, are required to be applied to the Term Facility. The Syndicate has agreed to apply these proceeds first to the Q1 2023 amortization payment with the remaining proceeds applied to the balance at maturity. No further amortization payments were required to be made during the quarter.

A total of \$235.0 million was drawn as of March 31, 2023 (December 31, 2022 – \$235.0 million). The interest rate applicable to the drawn amounts as of this date was 8.68% (December 31, 2022 – 8.38%).

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Financial Covenants:

The following table summarizes the financial covenants applicable to the SLL Facility and Term Facility at March 31, 2023:

Covenant Description	Position as at March 31, 2023	Covenant ⁽⁵⁾
Total Debt ⁽¹⁾ to EBITDA ⁽²⁾ Ratio	1.1:1.0	<3.0:1.0
Senior Debt ⁽³⁾ to EBITDA ⁽²⁾ Ratio	0.7:1.0	<2.5:1.0
Debt Service Coverage ⁽⁴⁾ Ratio	3.2:1.0	>1.5:1.0

⁽¹⁾ "Total Debt" is calculated in accordance with the credit facility agreements as all Debt of the Company excluding capitalized lease obligations and Letters of Credit of \$5.0 million outstanding as at March 31, 2023 and including indebtedness under the deferred acquisition notes issued on closing of the Deltastream acquisition.

⁽²⁾ "EBITDA" is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on the previous four quarters including the impact of material acquisitions as if they had occurred at the beginning of the four quarters.

⁽³⁾ "Senior Debt" is calculated in accordance with the credit facility agreements as Total Debt minus the SL Notes and permitted junior debt, including the Deferred Acquisition Payment Notes.

⁽⁴⁾ "Debt Service Coverage" is calculated as the ratio of EBITDA to cash interest expense plus scheduled principal payments on Total Debt for the twelve months ending at the end of each fiscal quarter.

⁽⁵⁾ Covenants in effect while the Term Facility and Deferred Acquisition Payment Notes are outstanding after which time the covenants will change to 3.5:1.0, 3.0:1.0 and 3.0:1.0, respectively.

(b) SL Notes:

During 2022, the Company issued \$300.0 million aggregate principal amount of 7.25% senior unsecured sustainability-linked notes due May 10, 2027 ("SL Notes"). The notes were offered through private placement underwriting agreements entered into in 2022. The SL Notes were issued under a trust indenture and are general unsecured obligations of Tamarack ranking pari passu with all of the Company's existing and future senior unsecured indebtedness.

As at March 31, 2023 the carrying value of the SL Notes of approximately \$288.4 million was net of approximately \$11.6 million of discounts and unamortized deferred financing costs incurred in conjunction with the issuance of the SL Notes. As at March 31, 2023 there was \$300.0 million principal outstanding on the SL Notes (December 31, 2022 – \$300.0 million). The next coupon payment date is set for May 10, 2023 in the amount of approximately \$10.9 million.

(c) Deferred Acquisition Payment ("DAP") Notes:

On October 13, 2022, the Company issued \$300.0 million aggregate principal amount of DAP Notes. There are no financial covenants governing the DAP Notes. The DAP Notes were issued under a trust indenture and are unsecured and payable in cash quarterly over an 18-month period in an amount equal to the lesser of \$50.0 million and the aggregate principal amount of all outstanding notes.

On March 31, 2023, the Company made its second principal payment in the amount of \$50.0 million. Interest on the DAP Notes is incurred at 5.75% per annum and is paid quarterly in arrears. The Company paid \$3.7 million of interest concurrent with the principal payment. The next payment date is set for June 30, 2023.

At March 31, 2023 the aggregate outstanding principal of the DAP Notes is approximately \$206.7 million (December 31, 2022 – \$256.7 million).

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Notes to the Condensed Consolidated Interim Financial Statements

For the three months ended March 31, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

12. Other liabilities:

	March 31, 2023	December 31, 2022
Cash award incentive plan	\$9,996	\$6,424
Current other liabilities	\$9,996	\$6,424
Cash award incentive plan	\$3,680	\$5,567
Facilities acquisition payments	4,416	4,292
Government loan	17,112	15,887
Long-term other liabilities	\$25,208	\$25,746

(a) Government loan:

On January 16, 2023 the Company entered into an agreement to receive an estimated \$7.8 million of additional funding through its methane conservation program. As at March 31, 2023 the Company has recorded a discounted liability of \$17.1 million of government assistance, which includes \$1.6 million recognized in the three months ended March 31, 2023, that is repayable under the terms of the Federal Government of Canada Emissions Reduction Fund (“ERF”) agreements. The ERF agreements include scheduled repayments of approximately \$1.9 million on March 31, 2025, \$6.6 million on March 31, 2026, \$11.5 million on March 31, 2027 and a final payment of \$0.8 million on March 31, 2028. The repayable government loan funding will be interest-free based on the Company’s compliance with the terms and conditions of the ERF funding agreements and all repayments made in accordance with the above noted repayment schedule.

13. Finance expense:

	Three months ended March 31,	
	2023	2022
Interest and fees on SLL Facility (note 11)	\$8,155	\$4,761
Interest and fees on Term Facility (note 11)	5,107	–
Interest and fees on SL Notes (note 11)	6,059	2,249
Interest on DAP Notes (note 11)	3,685	–
Interest on lease liabilities	180	181
Accretion on government loan and Facilities acquisition payments (note 12)	354	–
Other interest	2,560	–
Unrealized gain on foreign exchange	(8,810)	(5,751)
Unrealized loss on cross-currency swap	8,242	5,819
Accretion of decommissioning obligations (note 8)	2,253	1,288
Total finance expense	\$27,785	\$8,547

TAMARACK VALLEY ENERGY LTD.

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For the three months ended March 31, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

14. Shareholders' equity:

(a) Share capital:

(\$ thousands)	March 31, 2023		December 31, 2022	
	Number	Amount	Number	Amount
Balance, opening	556,440,901	\$1,879,250	406,938,099	\$1,242,392
Issue of common shares - cash	–	–	38,334,100	143,753
Issue of common shares - acquisitions	–	–	115,575,033	515,402
Issue of common shares - Option, RSU and PSU exercise	359,894	–	3,485,469	–
Purchase of common shares - cancellation	–	–	(4,362,700)	(14,375)
Return of common shares to treasury	–	–	–	(2,646)
Purchase of common shares - Option, RSU and PSU exercise	–	–	(3,529,100)	–
Share issue costs, net of tax (2023 - \$nil; 2022 - \$1,576)	–	–	–	(5,276)
Balance, ending	556,800,795	\$1,879,250	556,440,901	\$1,879,250

At March 31, 2023 and at December 31, 2022 the Company was authorized to issue an unlimited number of common shares ("Common Shares") and preferred shares without nominal or par value.

(b) Normal course issuer bid:

Pursuant to the Company's approved NCIB, the Company is permitted to purchase up to 27.8 million Common Shares over a period of twelve months commencing on January 19, 2023. During the three months ended March 31, 2023, the Company did not purchase and cancel any Common shares. For the year ended December 31, 2022, the Company purchased and cancelled 4.4 million Common Shares at an average price of \$4.26 per Common Share, for a total repurchase cost of \$18.6 million.

(c) Treasury shares:

During the three months ended March 31, 2023, the Company did not acquire any Common Shares to be used to settle stock options ("Stock Options"), RSUs and PSUs on the date of exercise (December 31, 2022 - \$17.3 million to purchase 3.5 million Common Shares). As at March 31, 2023, 139,869 Common Shares remain classified as treasury shares to be used for future settlements of Stock Options, RSUs and PSUs (December 31, 2022 – 499,763 Common Shares).

(d) Dividends:

During the three months ended March 31, 2023, the Company declared \$20.9 million (March 31, 2022 - \$10.6 million) related to its monthly cash dividends on its common shares of \$0.0125 per share (March 31, 2022 - \$0.0083 per share). Included within Accounts payable and accrued liabilities is the dividend payable of \$7.0 million on its common shares of \$0.0125 per share for the dividend declared on March 15, 2023.

Subsequent to March 31, 2023, the Company's Board of Directors declared the monthly cash dividend of \$0.0125 per share on April 15, 2023.

These monthly cash dividends are designated as "eligible dividends" for Canadian income tax purposes.

TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three months ended March 31, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

15. Net income per share:

The following table summarizes the net income and weighted average shares used in calculating net income per share:

(\$ thousands, except per share amounts)	Three months ended March 31,	
	2023	2022
Net income	\$2,505	\$26,457
Weighted average shares - basic	556,548	419,251
Weighted average shares - diluted	560,503	427,546
Net income per share-basic	–	\$ 0.06
Net income per share-diluted	–	\$ 0.06

Per share amounts have been calculated using the weighted average number of Common Shares outstanding. For the three months ended March 31, 2023, 9.0 million Common Shares issuable upon the exercise and/or settlement of Stock Options, RSUs and PSUs were included in the diluted weighted average number of Common Shares outstanding. For the three months ended March 31, 2022, 12.0 million Common Shares issuable upon the exercise and/or settlement of Stock Options, RSUs and PSUs were included in the diluted weighted average number of Common Shares outstanding.

16. Share-based payments:

The following table summarizes stock-based compensation expense relating to Stock Options, RSUs, PSUs, RIAs and PIAs:

	Three months ended March 31,	
	2023	2022
Stock Options	\$55	\$38
RSUs	1,705	815
PSUs	644	1,082
Equity settled stock-based compensation	\$2,404	\$1,935
RSUs	\$(504)	\$ –
PSUs	960	–
RIAs	663	116
PIAs	566	190
Cash settled stock-based compensation	\$1,685	\$306
Total capitalized costs	\$(1,303)	\$(709)
Total expensed stock-based compensation	\$2,786	\$1,532

Pursuant to the Company's stock option plan (the "Stock Option Plan"), the Company's performance and restricted share unit plan (the "PRSU Plan") and the Company's cash award incentive plan (the "CAI Plan"), the Company may grant up to an aggregate of 39.0 million Stock Options, RSUs, PSUs, RIAs and PIAs to officers, employees, directors and consultants of the Company or its subsidiaries, as applicable.

TAMARACK VALLEY ENERGY LTD.

Notes to the Condensed Consolidated Interim Financial Statements

For the three months ended March 31, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

(a) Stock Options:

The number and weighted average exercise prices of the Stock Options are as follows:

	Number of Stock Options (thousands)	Weighted average exercise price
Outstanding, January 1, 2022	2,142	\$2.22
Exercised – settled with Treasury shares (note 14)	(646)	2.73
Forfeited/expired	(118)	2.29
Outstanding, December 31, 2022	1,378	\$1.98
Exercised – settled with Treasury shares (note 14)	(124)	2.60
Outstanding, March 31, 2023	1,254	\$1.92

As at March 31, 2023, there were 1.3 million Stock Options issued and outstanding. There were no Stock Options granted during the three months ended March 31, 2023 (December 31, 2022 – nil).

The range of exercise prices of the Stock Options outstanding and exercisable at March 31, 2023 is as follows:

Range of exercise price	Stock Options outstanding			Stock Options exercisable	
	Number outstanding (thousands)	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable (thousands)	Weighted average exercise price
\$ 0.64 – 2.50	996	\$1.75	2.5	779	\$1.60
\$ 2.51 – 2.66	258	\$2.60	1.6	185	\$2.57
\$ 0.64 – 2.66	1,254	\$1.92	2.3	964	\$1.78

(b) PRSU Plan:

The following table summarizes information about the RSUs and PSUs:

	Number of RSUs (thousands)	Number of PSUs (thousands)
Outstanding, January 1, 2022	4,704	4,874
Granted	2,224	1,573
Reinvestment of dividends	59	37
Exercised - settled with shares from Treasury (note 14)	(2,007)	(833)
Exercised - cash payment	(680)	(570)
Forfeited	(328)	(670)
Outstanding, December 31, 2022	3,972	4,411
Granted	1,858	1,275
Reinvestment of dividends	19	11
Exercised - settled with shares from Treasury (note 14)	(174)	(62)
Forfeited	(143)	(96)
Outstanding, March 31, 2023⁽¹⁾	5,532	5,539
Exercisable, March 31, 2023⁽²⁾	1,377	1,701

⁽¹⁾ As at March 31, 2023, there are 542 outstanding cash settled RSUs and 2,773 outstanding cash settled PSUs remaining.

⁽²⁾ As at March 31, 2023, there are 254 exercisable cash settled RSUs and 1,140 exercisable cash settled PSUs remaining.

There were 1.9 million RSUs and 1.3 million PSUs granted during the three months ended March 31, 2023 (December 31, 2022 – 2.2 million RSUs and 1.6 million PSUs).

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Notes to the Condensed Consolidated Interim Financial Statements

For the three months ended March 31, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

(c) Cash Award Incentive Plan:

The following table summarizes information about the RIAs and PIAs:

	Number of RIAs (thousands)	Number of PIAs (thousands)
Outstanding, January 1, 2022	–	–
Granted	494	1,152
Forfeited	(60)	(140)
Outstanding, December 31, 2022	434	1,012
Granted	289	1,147
Outstanding, March 31, 2023	723	2,159
Exercisable, March 31, 2023	125	–

There were 0.3 million RIAs and 1.1 million PIAs granted during the three months ended March 31, 2023 (December 31, 2022 – 0.5 million RIAs and 1.2 million PIAs).

17. Government assistance:

(a) Decommissioning obligations:

The Company has recorded \$0.2 million of combined SRP and ASCP support payments received as a reduction to decommissioning obligations and recorded other income from the site rehabilitation program grant on the condensed consolidated interim statement of income and comprehensive income for the three months ended March 31, 2023 (March 31, 2022 - \$0.1 million).

(b) Emissions reductions:

On January 16, 2023 the Company entered into an agreement to receive as estimated \$7.8 million of additional funding through its methane conservation program. As at March 31, 2023 the Company has recorded \$29.3 million of combined ERF and Province of Alberta Methane Technology Implementation Program (“MTIP”) funding, which includes \$1.6 million recognized in the three months ended March 31, 2023. \$17.1 million is recognized as a discounted government loan and \$12.2 million is recognized as a government grant under the terms of the ERF and MTIP agreements, related to the Company’s construction of a methane conservation program. The ERF agreements include scheduled repayments for the repayable funding on March 31, 2025, March 31, 2026, March 31, 2027 and March 31, 2028 (see note 12(a)).

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Notes to the Condensed Consolidated Interim Financial Statements

For the three months ended March 31, 2023 and 2022

(unaudited)(thousands, except per share and per unit amounts or as otherwise indicated)

18. Commitments:

The following table summarizes the Company's commitments as at March 31, 2023:

(\$ thousands)	2023	2024	2025	2026	2027+
Bank debt ⁽¹⁾	65,000	170,000	556,663	–	–
SL Notes ⁽²⁾	–	–	–	–	300,000
Interest on SL Notes ⁽²⁾	21,750	21,750	21,750	21,750	7,746
DAP Notes ⁽³⁾	150,000	56,667	–	–	–
Interest on DAP Notes ⁽³⁾	6,779	826	–	–	–
Lease obligations	5,119	3,585	2,566	418	467
Government loan ⁽⁴⁾	–	–	1,939	6,601	12,295
Take or pay commitments ⁽⁵⁾	16,313	17,903	18,337	16,308	50,500
Processing commitments ⁽⁶⁾	2,398	3,038	9,276	9,276	67,305
Gas transportation ⁽⁷⁾	4,854	4,367	464	102	33
Capital commitments ⁽⁸⁾	10,620	25,722	–	–	–
Total	282,833	303,858	610,995	54,455	438,346

(1) Term facility matures on October 13, 2024 with quarterly amortization payments. SLL Facility matures on October 13, 2025 with no mandatory principal repayments prior to maturity. Excludes interest on bank debt as interest payments fluctuate based on floating rates of interest and changes in the outstanding balance. Subsequent to March 31, 2023 the Company extended the SLL Facility to a maturity of May 5, 2026.

(2) Principal amount of the SL Notes. SL Notes bear a coupon rate of 7.25%, payable semi-annually in arrears.

(3) Principal amount of the DAP Notes. DAP Notes bear a coupon rate of 5.75%, payable quarterly.

(4) Relates to the scheduled payments on the repayable government loan funding receivable from the Government of Canada under the terms of the ERF agreements.

(5) Pipeline commitments to deliver crude oil and/or crude oil and condensate for various volumes ranging from minimums of 65 m3/d to 1,589 m3/d at various tariffs ranging from \$9.00/m3 to \$25.22/m3 which expire between June 30, 2023 and December 31, 2030. Certain of these pipeline commitments escalate at 2% per annum.

(6) Processing commitments to guarantee firm capacity in various facilities.

(7) Gas transportation costs on long term firm contracts which are in various locations at variable rates.

(8) Initial aggregate commitments of \$240.0 million of capital to further develop the GORR Nipisi/Clearwater and Grande Prairie lands prior to March 31, 2024.

19. Contingency:

During 2019, the Company was served with a Statement of Claim from two joint interest owners that hold minority interests in a Unit, which is majority owned and operated by the Company. The plaintiffs are seeking judgment in the amount of \$56.0 million for unlawful conversion of their minority Unit interests (such amount based upon the alleged value of their minority Unit interests) or alternatively, judgment in the amount of \$1.65 million, representing the amounts allegedly owed by the Company plus punitive damages, interest and other costs. The minority Unit owners have also alleged the Company has breached its fiduciary duties owing to the minority Unit owners and that without the approval of the minority Unit owners, the Company has conducted operations within the Unit area and outside of the Unit area without the approval of the minority Unit owners.

The Company has filed a Statement of Defence denying all material allegations of the minority Unit owners. The Company believes the claims are without merit and the amounts are unsubstantiated. Therefore, no provision for any amount has been recorded in these condensed consolidated interim financial statements.

CORPORATE INFORMATION

Directors

John Rooney - Chairman ⁽¹⁾⁽³⁾⁽⁴⁾

Jeff Boyce ⁽¹⁾⁽⁴⁾

John Leach ⁽¹⁾⁽²⁾

Kathleen Hogenson ⁽²⁾⁽⁴⁾

Rob Spitzer ⁽²⁾⁽³⁾

Marnie Smith ⁽¹⁾⁽³⁾

Caralyn Bennett

Brian Schmidt

⁽¹⁾ Member of the Audit Committee of the Board of Directors

⁽²⁾ Member of the Reserves Committee of the Board of Directors

⁽³⁾ Member of the Compensation & Governance Committee of the Board of Directors

⁽⁴⁾ Member of the Environmental, Safety and Sustainability Committee of the Board of Directors

Management Team

Brian Schmidt
President & Chief Executive Officer

Steve Buytels
VP Finance & Chief Financial Officer

Kevin Screen
Chief Operating Officer

Ben Stoodley
VP Engineering

Christine Ezinga
VP Corporate Planning & Business Development

Scott Shimek
VP Production & Operations

Lynne Chrumka
VP Exploration

Sony Gill
Corporate Secretary

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

Stikeman Elliott LLP

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange

Stock symbol: TVE

Contact Information

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