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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Tamarack Valley Energy Ltd.

Opinion

We have audited the consolidated financial statements of Tamarack Valley Energy Ltd. (the "Company"), which comprise:

- the consolidated balance sheets as at December 31, 2021 and December 31, 2020
- the consolidated statements of income (loss) and comprehensive income (loss) for the years then ended
- the consolidated statements of changes in shareholders' equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2021 and December 31, 2020, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "*Auditors' Responsibilities for the Audit of the Financial Statements*" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2021.

KPMG LLP, an Ontario limited liability partnership and member firm of the KPMG global organization of independent member firms affiliated with KPMG International Limited, a private English company limited by guarantee. KPMG Canada provides services to KPMG LLP.

These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

We have determined the matters described below to be the key audit matters to be communicated in our auditors' report.

Assessment of the recoverable amount of the Viking oil, Cardium oil and Penny oil cash-generating units

Description of the matter

We draw attention to note 2, note 3 and note 9 to the financial statements. The Company assesses at each reporting date whether there is an indication that each of the Company's cash-generating units ("CGUs") may be impaired or that historical impairment may be reversed. Significant management judgments are required to analyze the relevant external and internal indicators of impairment or impairment reversal, and whether impairment testing is required. If any such indicators exist, then the recoverable amount is estimated. The Company identified an indicator of impairment reversal at December 31, 2021 in each of the Viking oil, Cardium oil and Penny oil CGUs and performed an impairment test to estimate the recoverable amount of each of these CGUs. The Company has recorded an aggregate impairment reversal of $390.0 million related these CGUs for the year ended December 31, 2021.

The estimated recoverable amount of each CGU involves significant estimates, including:

- The estimate of proved and probable oil and natural gas reserves and the related cash flows
- The discount rates.

The estimate of proved and probable oil and natural gas reserves and the related cash flows includes significant assumptions related to:

- Forecasted oil and natural gas commodity prices
- Forecasted production
- Forecasted production costs
- Forecasted royalty costs
- Forecasted future development costs.

The estimated proved and probable oil and natural gas reserves and the related cash flows are evaluated by external independent qualified reserves evaluators at least annually.

Why the matter is a key audit matter

We identified the assessment of the recoverable amount of the Viking oil, Cardium oil and Penny oil CGUs as a key audit matter. Significant auditor judgment was required to evaluate the results of our audit procedures regarding the estimate of proved and probable oil and natural gas reserves and the related cash flows and the discount rates.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

With respect to the estimate of proved and probable oil and natural gas reserves and the related cash flows:

- We evaluated the competence, capabilities and objectivity of the external independent qualified reserves evaluator engaged by the Company
- We compared the forecasted oil and natural gas commodity prices to those published by other external independent qualified reserves evaluators
- We compared the 2021 actual production, production costs, royalty costs and development costs of the Company to those estimates used in the prior year's estimate of proved oil and natural gas reserves and the related cash flows to assess the Company's ability to accurately forecast
- We evaluated the appropriateness of forecasted production and forecasted production costs, royalty costs and future development costs assumptions by comparing to 2021 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

We involved valuation professionals with specialized skills and knowledge, who assisted in:

- Evaluating the appropriateness of the Company's discount rates by comparing the discount rates to market and other external data
- Assessing the reasonableness of the Company's estimate of the recoverable amount of each CGU by comparing the Company's estimate to market metrics and other external data.

Evaluation of the acquisition-date fair value of oil and natural gas interests of Anegada Oil Corp.

Description of the matter

We draw attention to note 2, note 3, note 4 and note 7 to the financial statements. The Company acquired all of the issued and outstanding common shares of Anegada Oil Corp. on June 1, 2021 (the "acquisition-date") for total consideration of $538.4 million (the "Acquisition"). In connection with the Acquisition, the Company recorded oil and natural gas interests with an estimated acquisition-date fair value of $677.7 million.

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 and the related cash flows
- The discount rates.

The estimate of proved and probable oil and natural gas reserves and the related cash flows includes significant assumptions related to:

- Forecasted oil and natural gas commodity prices
- Forecasted production
- Forecasted production costs
- Forecasted royalty costs
- Forecasted future development costs.

For purposes of estimating the acquisition-date fair value of the oil and natural gas interests, the Company's internal reserves evaluator provided an estimate of proved and probable oil and natural gas reserves and the related cash flows.

Why the matter is a key audit matter

We identified the evaluation of the acquisition-date fair value of oil and natural gas interests of Anegada Oil Corp. as a key audit matter. Significant auditor judgment was required to evaluate the results of our audit procedures regarding the estimate of proved and probable oil and natural gas reserves and the related cash flows and the discount rates.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

With respect to the estimate of proved and probable oil and natural gas reserves and the related cash flows as at the acquisition-date:

- We evaluated the competence, capabilities and objectivity of the internal reserves evaluator
- We compared the forecasted oil and natural gas commodity prices to those published by other external independent qualified reserves evaluators
- We evaluated the appropriateness of forecasted production and forecasted production costs, royalty costs and future development costs assumptions by comparing to corresponding amounts in the proved and probable oil and gas reserves and the related cash flows estimated by the external independent qualified reserves evaluators as at December 31, 2021. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments between the acquisition-date and December 31, 2021.

With respect to the estimate of proved and probable oil and natural gas reserves and the related cash flows as at December 31, 2021:

- We evaluated the competence, capabilities and objectivity of the external independent qualified reserves evaluator engaged by the Company
- We compared the forecasted oil and natural gas commodity prices to those published by other external independent qualified reserves evaluators
- We evaluated the appropriateness of forecasted production and forecasted production costs, royalty costs and future development costs assumptions by comparing to 2021 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

We involved valuation professionals with specialized skills and knowledge, who assisted in:

- Evaluating the appropriateness of the Company's discount rates by comparing the discount rates to market and other external data
- Assessing the reasonableness of the Company's estimate of the acquisition-date fair value of oil and natural gas interests by comparing the Company's estimate to market metrics and other external data.

Other Information

Management is responsible for the other information. Other information comprises the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.
  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.
- Determine, from the matters communicated with those charged with governance, those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditors' report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our auditors' report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this auditors' report is Brad William Robertson.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
March 3, 2022

TAMARACK VALLEY ENERGY LTD.

Consolidated Balance Sheets
(thousands)

	December 31, 2021	December 31, 2020
Assets		
Current assets:		
Accounts receivable (note 5)	**$79,904**	$30,781
Prepaid expenses and deposits	**7,829**	1,265
Fair value of financial instruments (note 5)	**–**	981
	87,733	33,027
Fair value of financial instruments (note 5)	**77**	–
Property, plant and equipment (note 7, 8 and 9)	**2,236,535**	943,430
Exploration and evaluation assets (note 10)	**3,808**	1,460
Deferred tax asset (note 15)	**–**	49,683
	$2,328,153	$1,027,600
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$72,188**	$38,903
Lease liabilities (note 13)	**3,600**	2,484
Decommissioning obligations (note 11)	**5,298**	6,000
Cross-currency swap (note 16)	**292**	1,597
Fair value of financial instruments (note 5)	**13,146**	9,942
	94,524	58,926
Bank debt (note 16)	**477,437**	210,857
Lease liabilities (note 13)	**6,932**	7,670
Fair value of financial instruments (note 5)	**17**	1,192
Decommissioning obligations (note 11)	**279,174**	239,437
Other liability (note 21 and 22)	**1,100**	–
Deferred tax liability (note 15)	**208,344**	–
	1,067,528	518,082
Shareholders' equity:		
Share capital (note 18)	**1,242,392**	876,124
Treasury shares (note 18)	**(3,336)**	(703)
Contributed surplus	**48,311**	51,347
Deficit	**(26,742)**	(417,250)
	1,260,625	509,518
Subsequent events (note 5 and 24)		
Commitments (note 22)		
Contingency (note 23)		
	$2,328,153	$1,027,600

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:

(signed)
John Rooney
Director

(signed)
John Leach
Director

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)
For the years ended December 31, 2021 and 2020
(thousands, except per share amounts)

	2021	2020
Revenue:		
Oil and natural gas (note 6)	**$698,572**	$220,896
Processing income (note 6)	**2,479**	1,177
Royalties	**(102,132)**	(24,540)
Net revenue	**598,919**	197,533
Financial instrument contracts:		
Realized gain (loss) on financial instruments (note 5)	**(80,723)**	32,936
Unrealized gain (loss) on financial instruments (note 5)	**6,676**	(6,067)
Net revenue and gains (losses) on financial instruments	**524,872**	224,402
Expenses:		
Production	**117,957**	78,893
Transportation	**20,457**	7,622
General and administration	**18,039**	11,082
Transaction costs (note 7)	**8,110**	–
Stock-based compensation (note 20)	**5,970**	5,500
Finance (note 17)	**26,340**	12,635
Depletion, depreciation and amortization (note 8 and 10)	**212,337**	120,658
Gain on disposition of property, plant and equipment (note 7 and 8)	**(8,739)**	(10,665)
Site rehabilitation program grant (note 11 and 21)	**(5,365)**	(1,395)
Impairment (reversal) of property, plant and equipment (note 8 and 9)	**(390,000)**	399,000
	5,106	623,330
Income (loss) before taxes	**519,766**	(398,928)
Deferred income tax recovery (expense) (note 15)	**(129,258)**	87,544
Net income (loss) and comprehensive income (loss)	**$390,508**	$(311,384)
Net income (loss) per share (note 19):		
Basic	**$ 1.10**	$(1.40)
Diluted	**$ 1.08**	$(1.40)

See accompanying notes to the consolidated financial statements.

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Changes in Shareholders' Equity
(thousands)

	Number of common shares, net of treasury shares	Share capital	Treasury shares	Contributed surplus	Deficit	Total Shareholders' equity
Balance at December 31, 2019	222,793	$832,799	$(969)	$47,811	$(105,866)	$773,775
Issue of common shares	40,925	47,064	–	–	–	$47,064
Purchase of common shares for cancellation	(664)	(2,551)	–	1,262	–	(1,289)
Purchase of common shares for RSU exercise	(3,641)	–	(3,857)	–	–	(3,857)
RSU exercise	3,363	–	4,123	(4,123)	–	–
Share issue costs, net of tax of $368	–	(1,188)	–	–	–	(1,188)
Stock-based compensation	–	–	–	6,397	–	6,397
Net loss	–	–	–	–	(311,384)	(311,384)
Balance at December 31, 2020	262,776	$876,124	$(703)	$51,347	$(417,250)	$509,518
Balance at December 31, 2020	262,776	$876,124	$(703)	$51,347	$(417,250)	$509,518
Issue of common shares	143,564	365,427	–	–	–	365,427
Purchase of common shares for RSU and PSU exercise	(4,238)	–	(12,983)	–	–	(12,983)
RSU and PSU exercise	4,047	–	10,350	(10,350)	–	–
Transfer on option exercise	–	1,023	–	(1,023)	–	–
Option exercise	482	1,623	–	–	–	1,623
Preferred shares settlement	307	1,104	–	(381)	–	723
Share issue costs, net of tax of $869	–	(2,909)	–	–	–	(2,909)
Stock-based compensation	–	–	–	8,718	–	8,718
Net income	–	–	–	–	390,508	390,508
Balance at December 31, 2021	406,938	$1,242,392	$(3,336)	$48,311	$(26,742)	$1,260,625

See accompanying notes to the consolidated financial statements.

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Cash Flows
For the years ended December 31, 2021 and 2020

(thousands)

	2021	2020
Cash provided by (used in):		
Operating:		
Net income (loss)	**$390,508**	$(311,384)
Depletion, depreciation and amortization (note 8 and 10)	**212,337**	120,658
Stock-based compensation (note 20)	**5,970**	5,500
Gain on disposition of property, plant and equipment (note 7 and 8)	**(8,739)**	(10,665)
Site rehabilitation program grant (note 11 and 21)	**(5,365)**	(1,395)
Accretion expense on decommissioning obligations (note 11)	**4,895**	2,573
Unrealized loss (gain) on financial instruments (note 5)	**(6,676)**	6,067
Unrealized loss on foreign exchange	**1,266**	1,249
Unrealized gain on cross-currency swap (note 17)	**(1,305)**	(1,311)
Impairment (reversal) of property, plant and equipment (note 8 and 9)	**(390,000)**	399,000
Deferred income tax expense (recovery) (note 15)	**129,258**	(87,544)
Abandonment expenditures (note 11)	**(4,466)**	(3,825)
Changes in non-cash working capital (note 14)	**(29,789)**	6,367
Cash provided by operating activities	**297,894**	125,290
Financing:		
Change in bank debt (note 16)	**265,314**	16,701
Repayment of acquired debt (note 7)	**(37,734)**	–
Net proceeds from issuance of shares (note 18)	**71,227**	45,508
Purchase of common shares for cancellation (note 18)	**–**	(1,289)
Purchase of common shares for RSU and PSU exercises (note 18)	**(12,983)**	(3,857)
Net proceeds from option exercises (note 18)	**1,623**	–
Repayment of lease liabilities (note 13)	**(3,160)**	(2,348)
Payment for settlement of preferred shares (note 18)	**(116)**	–
Changes in other liability (note 21)	**1,100**	–
Changes in non-cash working capital (note 14)	**(2,105)**	1,556
Cash provided by financing activities	**283,166**	56,271
Investing:		
Property, plant and equipment additions (note 8)	**(187,564)**	(102,975)
Exploration and evaluation additions (note 10)	**(3,595)**	(568)
Acquisitions (note 7)	**(456,256)**	(98,811)
Proceeds from disposal of property, plant and equipment (note 7 and 8)	**46,217**	15,525
Changes in non-cash working capital (note 14)	**20,138**	5,268
Cash used in investing activities	**(581,060)**	(181,561)
Change in cash and cash equivalents	**–**	–
Cash and cash equivalents, beginning of year	**–**	–
Cash and cash equivalents, end of year	**$ –**	$ –

See accompanying notes to the consolidated financial statements.

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 subsidiaries. The Company has the following wholly owned subsidiaries, which are incorporated in Canada, as at December 31, 2021: Tamarack Acquisition Corp. and Tamarack Valley Ridge Holdings Ltd. The Company also has a subsidiary incorporated in the United States: Tamarack Ridge Resources Inc. No assets are held within Tamarack Ridge Resources Inc. or Tamarack Valley Ridge Holdings Ltd. On January 1, 2022 the Canadian subsidiaries were amalgamated into Tamarack Valley Energy Ltd. 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 consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements were authorized for issue by the Board of Directors on March 3, 2022.

(b) Basis of measurement:

The consolidated financial statements have been prepared on the historical cost basis except for certain derivative financial instruments (including cross-currency swaps) which are measured at fair value.

(c) Functional and presentation currency:

These consolidated financial statements are presented in Canadian dollars, which is the Company's and its subsidiaries functional currency, other than Tamarack Ridge Resources Inc. that has a United States dollar functional currency.

(d) Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

i) Critical judgments in applying accounting policies

The following are critical judgments that management has made in the process of applying accounting policies and that have the most significant effect on the amounts recognized in the consolidated financial statements.

The Company's assets are aggregated into cash-generating units for the purpose of calculating impairment. Cash-generating units" ("CGU" or "CGUs") are based on an assessment of the unit's ability to generate independent cash inflows. The determination of these CGUs was based on management's judgment pertaining to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality.

The Company's CGUs as at December 31, 2021 include the following:

- Clearwater oil
- Charlie Lake oil
- Viking oil
- Cardium oil
- Penny oil
- Minor gas

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 and the related cash flows being significant to the assessment.

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of proved and/or probable oil and natural gas reserves have been found in assessing if technical feasibility and commercial viability has been achieved.

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 requiring the acquisition method of accounting for a business combination or an asset acquisition when applying the optional asset concentration test.

Judgments are made by management to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings.

ii) Key sources of estimation uncertainty

The following are key sources of estimation uncertainty and key estimates and their assumptions made by management affecting the measurement of balances and transactions in these consolidated financial statements.

Climate change and COVID-19:

Climate change:

The Company has considered the impact of the evolving worldwide demand for carbon-based energy and global advancement of alternative energy sources. The impacts of climate change and the advancement of the transition to alternative energy sources is a source of uncertainty and impacts on key estimates and their assumption made by management affecting the measurement of balances and transaction in these consolidated financial statements. The impact of uncertainties regarding climate change and the effect they may have on management's estimates may impact on property, plant and equipment, depletion, impairment and impairment reversal, reserves estimates, decommissioning obligations, credit facilities and share capital. The discussion of specific climate change uncertainties, risks and or the Company's actions can be found within these notes to the consolidated financial statements.

COVID-19:

Tamarack continues to proactively respond to the safety and financial challenges of the COVID-19 pandemic. Management notes that forecasting the timing of a full and sustainable economic recovery is challenging with the outlook on crude oil demand significantly dependent on the status of COVID-19 virus variants, vaccine effectiveness, global vaccine rollouts, changes in social and travel restrictions, and the impact of all of these factors on global economic activity. The recovery in oil demand as a result of the easing of COVID-19 restrictions, combined with a prudent supply policy implemented by the OPEC+ alliance, has resulted in crude oil prices recovering to pre-pandemic levels. However, the crude oil market remains subject to high levels of uncertainty given the emergence of the Omicron variant of the COVID-19 virus, which could result in renewed social and travel restrictions. Changes in global crude oil demand, supply and inventories could all be impacted by the COVID-19 pandemic in the near term and crude oil markets may continue to be subject to significant volatility in 2022. There has also been significant market volatility in energy shares and foreign exchange markets, and restrictions on the conduct of business in many jurisdictions.

The evolving impact of climate change and COVID-19 may have significant impacts on the Company, including, but not limited to:

- significant changes in revenue and cash flows due to increased volatility in oil and natural gas commodity pricing,
- changes in future revenue could result in impairment charges and, or reversals of historical impairment charges to long-term assets,
- increased risk of non-performance by the Company’s customers which could materially increase collection risk of accounts receivable and customer defaults on contracts, and
- prolonged demand destruction could negatively impact the Company’s ability to maintain liquidity.

These situations are dynamic and the ultimate duration, timing and magnitude of the impact of climate change and COVID-19 on the economy and the financial effects to the Company are not known at this time. Estimates and judgments made by management in the preparation of these consolidated financial statements are subject and will continue to be subject to a higher degree of measurement uncertainty. As an understanding of the impacts of these situations on commodity, credit and equity markets develops, there is amplified potential for changes in these estimates and judgments.

Measurement of financial statement balance and transactions:

The amounts recorded for depletion of property, plant and equipment; the provision of decommissioning obligations; business combinations and asset acquisitions; the realization of future taxable earnings for deferred income tax asset recognition; the determination of technical feasibility and commercial viability of exploration and evaluation assets; indicators of impairment or impairment reversal and amounts used in an impairment calculation are based on estimates of proved and probable oil and natural gas reserves and the related cash flows. By their nature, these estimates of proved and probable oil and natural gas reserves and the related cash flows 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. Tamarack’s estimated proved and probable oil and natural gas reserves and the related cash flows have been prepared at December 31 of each year by the Company’s external independent qualified reserves evaluator, who work with information provided by the Company to establish reserve determinations in accordance with National Instrument 51-101.

The Company estimates the decommissioning obligations for oil and natural gas wells and their associated production facilities and pipelines. In most instances, removal of assets and remediation occurs many years into the future. Amounts recorded for the decommissioning obligations and related accretion expense require assumptions regarding removal date, future environmental legislation, the extent of reclamation activities required, the engineering methodology for estimating cost, inflation estimates, future removal technologies in determining the removal cost, and the estimate of the liability specific discount rates to determine the present value of these cash flows.

The Company's estimate of stock-based compensation is dependent upon estimates of expected volatility and forfeiture rates as well as performance multipliers estimated by management on the Company's performance share units.

The Company's estimate of the fair value of derivative financial instruments and cross-currency swaps is dependent on estimated variables including forward curves for commodity prices, foreign exchange rates and interest rates, as well as volatility curves.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently by the Company and its subsidiaries to all years presented in these consolidated financial statements.

(a) **Basis of consolidation:**

i) Subsidiaries:

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, substantive potential voting rights are taken into account. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

ii) Business combinations:

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The excess of the cost of acquisition over the fair value of the identifiable assets acquired and liabilities and contingent liabilities assumed is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in profit or loss. Business combination associated transaction costs are expensed when incurred. Within the IFRS Business Combinations guidance, there is an optional fair value concentration test. The concentration test is a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or a group of similar identifiable assets. If an entity chooses not to apply the concentration test, or the test is failed, then the assessment focuses on the existence of a substantive process, and the acquisition is accounted for as a business combination. The cost of an acquisition that does not meet the definition of a business under IFRS and does not qualify as a business combination is measured as the fair value of the consideration given and liabilities incurred or assumed at the date of exchange. No goodwill arises on an asset acquisition and the cost of the assets acquired and liabilities assumed are allocated to the assets and liabilities on the basis of their relative fair values at the date of purchase. Asset acquisition associated transaction costs are capitalized as a cost of the acquisition.

iii) Jointly owned assets:

Many of the Company's oil and natural gas activities involve jointly owned assets. The consolidated financial statements include the Company's share of these jointly owned assets and a proportionate share of the relevant revenue and related costs. The relationship with jointly owned asset partners has been referred to as joint venture in the remainder of the consolidated financial statements as is common in the Canadian oil and gas industry.

iv) Transactions eliminated on consolidation:

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

(b) Financial instruments:

i) Financial instruments:

The Company recognizes financial assets and financial liabilities, including derivatives, on the balance sheet when the Company becomes a party to the contract. Financial assets are derecognized when the rights to receive cash flows from the assets have expired or when the Company has transferred substantially all risks and rewards of ownership. Financial liabilities are derecognized from the consolidated financial statements when the liability is extinguished either through settlement of, or release from, the obligation of the underlying liability.

Financial assets, financial liabilities and derivatives are measured at fair value on initial recognition. Measurement in subsequent periods depends on the financial instrument's classification, as described below.

- Amortized cost - A financial asset is measured at amortized cost if the objective of the business model is to hold the financial asset for the collection of the cash flows; and all contractual cash flows represent only principal and interest on that principal. All financial liabilities are measured at amortized cost using the effective interest method except for liabilities incurred for the purposes of selling or repurchasing in the short-term, if they are held-for trading and those that meet the definition of a derivative.
- Fair value through other comprehensive income ("FVOCI") - A financial asset shall be measured at FVOCI if the financial asset is held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets; and the contractual terms of the financial asset give rise on specified dates to cash flows that are Solely Payment of Principal and Interest ("SPPI") on the principal amount outstanding.
- Fair value through profit or loss ("FVTPL") - All financial assets that do not meet the definition of being measured at amortized cost or FVOCI are measured at FVTPL, this includes all derivative financial assets. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. For financial assets and liabilities, the Company may make an irrevocable election to designate an asset at FVTPL. If the election is made it is irrevocable, meaning that asset, liability, or group of financial instruments must be recorded at FVTPL until that asset, liability or group of financial instruments are derecognized.

Financial assets and liabilities are offset and the net amount is reported on the balance sheet when there is a legally enforceable right to offset the recognized amounts, and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Commodity contracts that are entered into and continue to be held for the purpose of the receipt or delivery of a commodity in accordance with the Company's expected purchase, sale or usage fall within the normal purchase or sale exemption and are accounted for as executory contracts. Financial assets are assessed with an expected credit loss model. The expected credit loss model applies to financial assets measured at amortized cost, a lease receivable, a contract asset or a loan commitment and a financial guarantee contract.

Accounts receivable, accounts payable and accrued liabilities and bank debt are measured at amortized cost while financial derivative contracts (including cross-currency swaps) are measured at FVTPL. The Company has not designated any financial instruments as FVOCI, nor does the Company use hedge accounting.

ii) Share capital:

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects. When the Company repurchases its own common shares, share capital is reduced by the average carrying value of the shares repurchased. The excess of the purchase price over the carrying value is recognized as a deduction from retained earnings or conversely credited to contributed surplus when the carrying value exceeds the purchase price. Shares are cancelled upon repurchase.

(c) Property, plant and equipment and exploration and evaluation ("E&E") assets:

i) Recognition and measurement:

E&E expenditures:

Pre–license costs are recognized in profit or loss as incurred.

E&E costs, including the costs of acquiring licenses, initially are capitalized as E&E assets. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability.

E&E assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, E&E assets are evaluated at a CGU level.

A review of each exploration license or field is carried out, at least annually, to ascertain whether technical feasibility and commercial viability have been established.

Upon determination that technical feasibility and commercial viability of E&E assets has been established, E&E assets attributable to those proved and probable oil and natural gas reserves are first tested for impairment and then reclassified from E&E assets to property, plant and equipment.

Development and production costs:

Items of property, plant and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into CGUs for impairment testing. When significant parts of an item of property, plant and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal or the fair value of the asset received or given up with the carrying amount of the related property, plant and equipment given up and are recognized net in profit or loss.

ii) Subsequent costs:

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable oil and natural gas reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day–to–day servicing of property, plant and equipment are recognized in profit or loss as incurred.

iii) Depletion, depreciation and amortization:

The net carrying value of development or production assets is depleted using the unit of production method by reference to the ratio of production in the year to the related proved and probable oil and natural gas reserves, taking into account estimated future development costs necessary to bring those reserves into production. Production and reserves of natural gas are converted to equivalent barrels of oil based on the energy equivalent ratio of six thousand cubic feet of natural gas to one barrel of oil. Future development costs are estimated by taking into account the level of development required to produce the reserves.

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 depletion on its oil and gas properties. Depletion of the Company's oil and gas properties is based on proved and probable reserves, the life of which is generally less than 20 years. At this time, the Company has not capped its reserve life (i.e. estimated maximum life) for purposes of the calculation of depletion expense, however, this estimate will be monitored as the energy evolution continues.

These estimates are reviewed by independent qualified reserves evaluators at least annually.

E&E assets pertaining to undeveloped land are amortized on a straight-line basis over the term of the lease.

For other assets, depreciation is recognized in profit or loss on a percentage basis based on the useful life of the assets.

The estimated depreciation rates for other assets for the current and comparative years are as follows:

Computer hardware and software	30 %
Office equipment, fixtures and fittings	20 %

Depreciation methods, useful lives and salvage values are reviewed at each reporting date.

(d) **Leased assets and liabilities:**

At inception of a contract, the Company assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether:

- the contract involves the use of an identified asset; this may be specified explicitly or implicitly and should be physically distinct or represent substantially all of the capacity of a physically distinct asset. If the supplier has a substantive substitution right, then the asset is not identified;
- the Company has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use; and
- the Company has the right to direct the use of the asset. The Company has this right when it has the decision-making rights that are most relevant to changing how and for what purpose the asset is used. In rare cases where the decision is predetermined, the Company has the right to direct the use of the asset if either:
  - i. the Company has the right to operate the asset; or
  - ii. the Company designed the asset in a way that predetermines how and for what purpose it will be used.

When the Company is a lessee, it recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The right-of-use asset is subsequently depreciated from the commencement date to the earlier of the end of useful life of the right-of-use assets or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. In addition, the right-of-use asset is reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate.

Lease payments included in the measurement of the lease liability comprise the following:

- fixed payments, including in-substance fixed payments;
- variable lease payments that depend on an index or rate, initially measured at the index or rate as at the commencement date; and
- amounts expected to be payable under a residual value guarantee; and the exercise price under a purchase option that the Company is reasonably certain to exercise, lease payments in an option renewal period if the Company is reasonably certain to exercise an extension option, and penalties for early termination of a lease unless the Company is certain not to terminate early.

The lease liability is measured at amortized cost using the effective interest method. It is re-measured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option.

When the lease liability is re-measured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amounts of the right-of-use asset has been reduced to nil.

The Company presents right-of-use assets in "property, plant and equipment" and lease obligations in "lease liabilities" in the consolidated balance sheet.

(e) **Impairment:**

i) Financial assets:

The Company recognizes loss allowances for expected credit losses" ("ECLs") on its financial assets measured at amortized cost. Due to the nature of its financial assets, the Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit loss and are discounted at the effective interest rate of the related financial asset.

ii) Non-financial assets:

The carrying amounts of the Company's non–financial assets, other than E&E assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any external or internal indicators of impairment or impairment reversal. If any such indicator exists, then the recoverable amount is estimated. E&E assets, which are evaluated with the related CGU when they are assessed for impairment, are assessed for impairment when they are reclassified to property, plant and equipment, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. Right-of-use assets may be tested as part of a CGU, as a separate CGU or as an individual asset.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposal.

Fair value less costs of disposal ("FVLCD") is determined to be the amount for which the asset could be sold in an arm's length transaction. In determining fair value less costs of disposal, discounted cash flows and recent market transactions are taken into account. These calculations are corroborated by valuation multiples or other available fair value indicators.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre–tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable oil and natural gas reserves.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the other assets in the unit or group of units on a pro rata basis.

Any impairment losses in respect of property, plant and equipment and E&E assets, recognized in prior years, are assessed at each reporting date for any indications that the losses have decreased or no longer exist. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount.

An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

(f) **Share based payments:**

The grant date fair value of preferred shares, stock options, restricted share units and performance share units granted to employees is recognized as compensation expense with a corresponding increase in contributed surplus over the vesting period. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of awards that vest.

(g) **Provisions:**

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre–tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

i) Decommissioning obligations:

The Company's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the balance sheet date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

ii) Onerous contracts:

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under the contract. The provision is measured at the present value of the lower of the expected cost of terminating the contract and the expected net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on associated assets.

(h) **Revenue:**

Revenues from the sale of oil, natural gas and NGL are measured based on the consideration specified in contracts with customers. The Company recognizes revenue when it transfers control of the product to the buyer and collection is reasonably assured. This is generally considered to occur when legal title to the product passes to customers, which is when it is physically transferred to the pipeline or other transportation method agreed upon. The nature of each of its performance obligations, including roles of third parties and partners, are evaluated to determine if the Company acts as a principal, and therefore recognizes revenue on a gross basis, or as an agent, and therefore recognizes revenue on a net basis. The Company acts as the principal when it controls the product delivered before the control passes to its customer. Revenues from processing activities are recognized over time as processing occurs, and generally billed monthly.

(i) **Finance income and expenses:**

Finance expense is comprised of interest expense on bank debt, interest expense on lease liabilities, unrealized foreign exchange translation gains or losses, unrealized gains or losses on cross-currency swaps, accretion of the discount on decommissioning obligations and impairment losses recognized on financial assets.

Borrowing costs incurred for the construction of qualifying assets are capitalized during the period of time that is required to complete and prepare the assets for their intended use or sale. All other borrowing costs are recognized in profit or loss using the effective interest method. The capitalization rate used to determine the amount of borrowing costs to be capitalized is the weighted average interest rate applicable to the Company’s outstanding borrowings during the period.

Transactions in foreign currencies are translated to Canadian dollars at exchange rates at the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the rate of exchange prevailing at the reporting date, while non-monetary assets and liabilities that are measured in terms of historical cost are translated using the exchange rates at the dates of the transactions. Foreign currency gains and losses are reported on a net basis as either finance income or finance expense depending on whether foreign currency movements are in a net gain or net loss position.

Interest income is recognized as it accrues in profit or loss, using the effective interest method.

(j) **Income tax:**

Income tax expense is comprised of current and deferred tax. Income tax expense is recognized in profit or loss, except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date.

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(k) **Earnings per share:**

Basic earnings per share is calculated by dividing the profit or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. The weighted average number of common shares is adjusted for shares purchased and held by the Company (treasury shares). Diluted earnings per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as preferred shares, stock options, restricted share units and performance share units granted to employees.

(l) **Government assistance**

The Company recognizes government assistance in the form of grants in relation to the Alberta Site Restoration Program ("SRP"), the Saskatchewan Accelerated Site Closure Program ("ASCP"), the Federal Emissions Reduction Fund ("ERF"), the Alberta Methane Technology Information Program ("MTIP") and the Canada Emergency Wage Subsidy ("CEWS"). Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to the grants and the grants will be received. Grants that relate to the purchase, construction or acquisition of long-term assets are recognized by deducting the grants received from the carrying amount of the long-term assets. Grants related to long-term assets are recognized in profit or loss over the life of the asset through depletion, depreciation and amortization. Government loans are accounted for in accordance with IFRS 9 *Financial Instruments*. Government loans that are at below-market interest rates are recognized and measured in accordance with IFRS 9 and the benefit of the below-market interest rate measured as the difference between the initial carrying value of the loan recognized in accordance with IFRS 9 and the loan received is accounted for according to the nature of the grant. Grants related to an obligation of the Company are recognized as a reduction in the obligation and in profit or loss when the conditions of recognition of the grant have been met. Grants that compensate the Company for expenses incurred are recognized as a reduction to the related expense on a systematic basis in the periods in which the expenses are recognized.

4. Determination of fair values:

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.

(a) Property, plant and equipment and E&E assets:

The fair value of property, plant and equipment recognized in an acquisition is based on market values. The market value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. 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 and the related cash flows and the discount rates. The estimate of proved and probable oil and natural gas reserves and the related cash flows includes significant assumptions related to forecasted oil and natural gas commodity prices, forecasted production, forecasted production costs, forecasted royalty costs and forecasted future development costs. The estimates of proved and probable oil and natural gas reserves and the related cash flows areas prepared by the Company's external independent qualified reserves evaluator or internal reserves evaluator. The market value of other items of property, plant and equipment and E&E assets is based on the quoted market prices for similar items.

(b) Accounts receivable, bank debt and accounts payable and accrued liabilities:

The fair value of accounts receivable and accounts payable and accrued liabilities is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2021 and 2020, the fair value of these balances approximated their carrying value due to their short term to maturity.

Bank debt bears a floating rate of interest and the margins charged by the lenders are indicative of current credit spreads and therefore carrying value approximates fair value.

(c) **Stock options, preferred shares, restricted share units and performance share units:**

The fair value of employee stock options and preferred shares is measured using a Black-Scholes option pricing model. Measurement inputs include share price on measurement date, exercise price of the instrument, expected volatility based on weighted average historic volatility, weighted average expected life of the instruments based on historical experience and general option holder behavior, expected dividend yield and the weighted average risk-free interest rate based on government bonds. Restricted share units and performance share units are valued at the share price on the measurement date.

(d) **Derivatives:**

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.

5. Financial Risk Management:

(a) **Overview:**

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities such as:

- credit risk;
- liquidity risk; and
- market risk.

This note presents information about the Company's exposure to each of the above risks, the Company's objectives, policies and processes for measuring and managing risk, and the Company's management of capital. Further quantitative disclosures are included throughout these consolidated financial statements.

The Board of Directors oversees managements' establishment and execution of the Company's risk management framework. Management has implemented and monitors compliance with risk management policies. The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls and to monitor risks and adherence to market conditions and the Company's activities.

(b) **Credit risk:**

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations and arises principally from the Company's receivables from joint venture partners and oil and natural gas marketers and favorable mark-to-market positions on financial instruments. The maximum exposure to credit risk at year-end is as follows:

($ thousands)	Carrying amount	
As at December 31,	**2021**	2020
Accounts receivable	**$79,904**	$30,781
Fair value of financial instruments	**77**	981
Total	**$79,981**	$31,762

Accounts receivable:

All of the Company's operations are conducted in Canada. The Company's exposure to credit risk is influenced mainly by the individual characteristics of each customer.

Receivables from oil and natural gas purchasers are normally collected on the 25th day of the month following production. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large purchasers. The Company historically has not experienced any collection issues with its oil and natural gas purchasers.

Receivables from joint venture partners are typically collected within one to three months of the joint venture bill being issued. The Company attempts to mitigate the risk from joint venture receivables by obtaining joint venture partner pre-approval of significant capital expenditures.

However, the receivables are from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs and the risk of unsuccessful drilling. In addition, further risk exists with joint venture partners; as disagreements occasionally arise that increase the potential for non-collection. The Company does not typically obtain collateral from oil and natural gas marketers or joint venture partners; however, the Company does have the ability to withhold production from joint venture partners in the event of non-payment.

Derivative assets consist of commodity contracts used to manage the Company's exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. The Company manages the credit risk exposure related to derivative assets by selecting investment grade counterparties and by not entering into contracts for trading or speculative purposes.

The Company does not anticipate any default as it transacts with creditworthy customers and management does not expect any losses from non-performance by these customers. The lifetime expected credit losses allowances related to the Company's oil and natural gas marketers and joint venture receivables were nominal as at and for the years ended December 31, 2021 and 2020.

The maximum exposure to credit risk for accounts receivable at the reporting date by type of customer was:

($ thousands) As at December 31,	Carrying amount 2021	2020
Oil and natural gas marketing companies	**$71,706**	$23,922
Joint venture partners	**4,930**	4,451
Other	**3,268**	2,408
Total accounts receivable	**$79,904**	$30,781

The Company's seven most significant customers (seven Canadian oil and natural gas marketers) account for $56.9 million of the account receivables at December 31, 2021 (December 31, 2020: four Canadian oil and natural gas marketers, and two joint venture partners accounted for $19.3 million).

As at December 31, 2021 and 2020, the Company's accounts receivable is aged as follows:

($ thousands)	2021	2020
Current (less than 90 days)	**$76,640**	$28,344
Past due (more than 90 days)	**3,264**	2,437
Total accounts receivable	**$79,904**	$30,781

(c) **Liquidity risk:**

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking damage to the Company's reputation.

Typically, the Company ensures that it has sufficient cash or available credit facility available to meet expected operational expenses for a period of 30 days, including the servicing of financial obligations; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted, such as natural disasters. To achieve this objective, the Company prepares annual capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month.

The timing of cash flows relating to financial liabilities as at December 31, 2021 is as follows:

($ thousands)	Total	Less than 1 Year	1 to 3 years	Beyond 3 years
Account payable and accrued liabilities	$72,188	72,188	$–	$–
Fair value of financial instruments	13,163	13,146	17	–
Cross currency swap	292	292	–	–
Other liability	1,100	–	–	1,100
Bank debt	477,437	–	477,437	–
Total financial liabilities	$564,180	$85,626	$477,454	$1,100

Refer to note 13 for a maturity analysis of the Company's lease liabilities.

(d) **Market risk:**

Market risk is the risk that changes in market prices, such as commodity prices, foreign exchange rates and interest rates will affect the Company's income or the value of the financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return.

The Company may use both financial derivatives and physical delivery contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors quarterly.

Currency risk:

Prices for oil are determined in global markets and generally denominated in United States dollars. Natural gas prices obtained by the Company are influenced by both US and Canadian demand and the corresponding North American supply. The exchange rate effect cannot be quantified but generally a decrease in the value of the $CDN as compared to the $US will increase the prices received by the Company for its petroleum and natural gas sales. The Company holds hedges to mitigate foreign exchange risk as detailed in the table below in addition to cross-currency swaps ("CCS") to remove the foreign exchange risk of LIBOR based borrowings (see notes 16 and 17). At December 31, 2021, the Company had drawn US$235.0 million, fixed at notional amounts of $297.5 million through CCS maturing across the month of January 2022 (December 31, 2020 – the Company had drawn US$111.0 million, fixed at notional amounts of $142.8 million through various CCS).

Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on the outstanding bank debt fluctuates with the interest rates posted by the lenders. Interest rates as posted by the lenders are subject to change based on market conditions and indicators. The interest rate charged by the lenders under the terms of the SLL Facility includes the potential for the interest rate to change based on the Company's achieving or missing on defined sustainability-linked targets (see note 16). The Company is exposed to interest rate risk and has entered into mitigating interest rate swaps to cover a portion of this exposure. Had the borrowing rate been 100 basis points higher (or lower) throughout the year ended December 31, 2021, net income would have been affected by $3,022 (December 31, 2020 – $1,557) based on the average debt balance outstanding during the year.

Commodity price risk:

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only the relationship between the Canadian and United States dollar but also world economic events that dictate the levels of supply and demand.

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

At December 31, 2021, the Company held derivative commodity, foreign exchange and interest rate contracts as noted in the following tables.

		Q1 2022	Q2 2022	Q3 2022	Q4 2022
West Texas Intermediate Crude Oil Derivatives					
WTI two-way collar	***Volume (bbls/d)***	**1,250**	**4,250**	**9,250**	**3,500**
	Average Bought Put (US$/bbl)	$52.60	$54.76	$58.57	$58.50
	Average Sold Call (US$/bbl)	$87.17	$90.46	$93.51	$92.13
	Average Premium (US$/bbl)	$2.00	$2.01	$2.00	$2.00
WTI three-way reverse collar	***Volume (bbls/d)***	**1,250**	**2,500**	**1,250**	**750**
	Average Bought Put (US$/bbl)	$55.00	$54.40	$55.00	$55.00
	Average Sold Call (US$/bbl)	$70.00	$70.00	$70.00	$70.00
	Average Bought Call (US$/bbl)	$73.29	$72.99	$73.37	$73.98
	Average Premium (US$/bbl)	$2.00	$2.00	$2.00	$2.00
WTI Put	***Volume (bbls/d)***	**19,750**	**7,750**	**750**	**750**
	Average Bought Put (US$/bbl)	$68.76	$52.71	$53.10	$53.10
	Average Premium (US$/bbl)	$3.97	$2.70	$3.10	$3.10
Crude Oil Differential Derivatives					
Edmonton Par to WTI fixed price differential swap	***Volume (bbls/d)***	**7,000**	**8,500**	**500**	**500**
	Average Price (US$/bbl)	($3.86)	($3.82)	($4.00)	($4.00)
WCS to WTI fixed price differential swap	***Volume (bbls/d)***	**3,000**	**4,000**	**500**	**500**
	Average Price (US$/bbl)	($12.58)	($11.79)	($12.00)	($12.00)

		Winter 21-22	Summer 22
Natural Gas Derivatives			
AECO 5A	***Volume (GJ/d)***	**25,000**	**30,000**
	Average Price (CAD/GJ)	$3.14	$2.44

		Q1 2022	Q2 2022	Q3 2022	Q4 2022
CAD/USD Foreign Exchange Derivatives					
CAD/USD average rate forward	***Amount ($US/month)***	**$7,000,000**	**$6,500,000**	–	–
	Average Forward Rate (CAD/USD)	1.2415	1.2440	–	–
CAD/USD target average rate forward(1)	***Amount ($US/month)***	**$1,500,000**	**$1,500,000**	**$500,000**	**$500,000**
	Average Forward Rate (CAD/USD)	1.2433	1.2433	1.2640	1.2640
CAD/USD forward accumulator(2)	***Amount ($US/month)***	**$833,333**	**$833,333**	–	–
	Average Forward Rate (CAD/USD)	1.2500	1.2500	–	–

(1) Comprised of three $500,000 tranches in Q1 and Q2 2022 and one $500,000 in Q3 and Q4 2021, with a maximum benefit to Tamarack over the term for each tranche of 0.03 value points; once maximum value is reached, the instrument immediately terminates.

(2) Accumulates for the monthly period at a rate of 1.25 based on the rate during the setting period six months prior.

		2022	2023	2024
Interest Rate Derivatives				
CDOR Interest Rate Fixed Price Swap	**Amount ($MM CAD/year)**	**$80.0**	**$49.1**	**$6.4**
	Fixed Interest Rate	1.533%	1.225%	1.043%

At December 31, 2021, Tamarack's derivative commodity, foreign exchange and interest rate contracts were fair valued with a net liability of $13,086 (December 31, 2020 - $10,153 net liability) recorded on the balance sheet. The Company had an unrealized gain of $6,676 recorded in earnings for the year ended December 31, 2021 (December 31, 2020 - $6,067 unrealized loss).

Subject Contract	Effect of an increase in oil price, gas price, exchange rate or interest rate on after-tax earnings	Effect of a decrease in oil price, gas price, exchange rate or interest rate on after-tax earnings
Cdn $1.00/bbl change in the oil price	($1,210)	$1,252
Cdn $0.10/gj change in the gas price	($705)	$705
Cdn $0.01 change in the exchange rate	($294)	$249
0.25% change in the interest rate	$827	($831)

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 December 31, 2021, the Company held the following physical commodity contracts:

		Winter 21-22
Natural Gas Physical		
AECO 5A	***Volume (GJ/d)***	**15,000**
	Average Price (CAD/GJ)	$3.00

Risk management contracts assets and liabilities 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.

The following table sets out gross amounts relating to risk management contracts assets and liabilities that have been presented on a net basis on the balance sheet.

Gross Amounts ($ thousands)	**December 31, 2021**	December 31, 2020
Risk management contracts		
Current asset	**$ –**	$981
Long-term asset	**77**	–
Current liability	**(13,146)**	(9,942)
Long-term liability	**(17)**	(1,192)
Balance, end of the period	**$(13,086)**	$(10,153)

Subsequent to December 31, 2021, the Company has entered into the following financial contracts (excluding contracts acquired in the acquisition of Crestwynd Exploration Ltd.):

		Q2 2022	**Q3 2022**	**Q4 2022**	**Q1 2023**
West Texas Intermediate Crude Oil Derivatives					
WTI two-way collar	***Volume (bbls/d)***	**–**	**2,500**	**8,500**	**3,500**
	Average Bought Put (US$/bbl)	**–**	$60.00	$57.06	$55.71
	Average Sold Call (US$/bbl)	**–**	$101.24	$111.96	$116.74
	Average Premium (US$/bbl)	**–**	$1.75	$1.93	$2.00
WTI Put	***Volume (bbls/d)***	**1,250**	**4,000**	**3,500**	**1,000**
	Average Bought Put (US$/bbl)	**$57.98**	$56.25	$57.14	$60.00
	Average Premium (US$/bbl)	**$0.75**	$2.98	$3.20	$3.27
Edmonton Par to WTI fixed price differential swap	***Volume (bbls/d)***	**2,000**	**7,500**	**7,500**	**–**
	Average Price (US$/bbl)	($3.00)	($3.57)	($3.57)	**–**
WCS to WTI fixed price differential swap	***Volume (bbls/d)***	**1,000**	**7,000**	**5,000**	**–**
	Average Price (US$/bbl)	($11.95)	($12.00)	($12.10)	**–**

		Winter 22-23
Natural Gas Derivatives		
AECO 5A	***Volume (GJ/d)***	**10,000**
	Average Price (CAD/GJ)	$3.85
AECO 7A two-way collar	***Volume (GJ/d)***	**15,000**
	Average Bought Put (CAD/GJ)	$3.37
	Average Sold Call (CAD/GJ)	$5.17

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

Subsequent to December 31, 2021, the Company entered into agreements to reprice certain agreements, raising the value of the bought puts and increasing the associated premiums. The values at December 31, 2021 and the new values after repricing are summarized in the table below.:

		As at Dec 31, 2021 **Q2 2022**	Subsequent to Year End **Q2 2022**
West Texas Intermediate Crude Oil Derivatives			
WTI two-way collar	***Volume (bbls/d)***	**500**	**500**
	Average Bought Put (US$/bbl)	$60.00	$65.00
	Average Sold Call (US$/bbl)	$95.50	$95.50
	Average Premium (US$/bbl)	$2.00	$2.98
WTI Put	***Volume (bbls/d)***	**6,500**	**6,500**
	Average Bought Put (US$/bbl)	$52.49	$65.00
	Average Premium (US$/bbl)	$3.03	$4.20

Since December 31, 2021, the Company has not entered into any physical contracts.

(e) 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, bank debt 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.

Tamarack uses quarterly 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. Quarterly adjusted funds flow is calculated by taking cash-flow from operating activities on a quarterly basis and adding back changes in non-cash working capital, expenditures on decommissioning obligations and transaction costs. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares that are used in calculating income (loss) per share.

Tamarack Management may also use free funds flow and year-end net debt to trailing annual adjusted funds flow in managing its capital structure. Free funds flow is calculated by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions. Year-end net debt to trailing annual adjusted funds flow is calculated as estimated year-end net debt divided by the estimated adjusted funds flow for the four preceding quarters at year-end.

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 outstanding bank debt plus accounts payable and accrued liabilities, cross-currency swap liabilities and other liability minus accounts receivable and prepaid expenses and deposits divided by adjusted funds flow for the most recent calendar quarter and then annualized. Tamarack calculates adjusted funds flow as cash provided by operating activities before the changes in non-cash working capital related to operating activities and abandonment expenditures. The Company's return of capital framework and dividend policy sets a net debt to trailing annual adjusted funds flow of 1.0 times after achieving its long-term debt target. This ratio may increase or decrease at certain times as a result of acquisitions, timing of employing capital versus bringing wells on production or significant upward/downward fluctuations in commodity prices.

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 December 31, 2021, the Company's ratio of net debt to annualized fourth quarter adjusted funds flow was 0.9 to 1 (December 31, 2020 – 1.9 to 1). The Company believes that available credit facilities combined with anticipated adjusted funds flow will be sufficient to satisfy Tamarack's 2022 development capital program and dividend payments for the 2022 fiscal year.

($ thousands)	**December 31, 2021**	December 31, 2020
Working capital deficiency (surplus)	**$(15,253)**	$8,454
Other liability	**1,100**	–
Bank debt	**477,437**	210,857
Net debt	**463,284**	219,311
Quarterly adjusted funds flow	**$124,080**	$28,894
Annualized factor	**4**	4
Annualized adjusted funds flow	**496,320**	115,576
Net debt to annualized adjusted funds flow	**0.9x**	1.9x

Neither the Company nor any of its subsidiaries are subject to externally imposed capital requirements. The credit facilities are subject to a semi-annual review of the borrowing base which is directly impacted by the value of the Company's estimated proved and probable oil and natural gas reserves.

6. 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. Revenues are normally collected on the business day nearest the 25th day of the month following sale.

The Company's revenues were primarily generated in its core areas: the Cardium oil play in the Wilson Creek/Alder Flats areas of central Alberta; the Viking oil play in central and southern Alberta and west central Saskatchewan; the Clearwater oil play in the Nipisi area of northern Alberta; the Charlie Lake oil play in the Grande Prairie area of northwestern Alberta and the Barons Sand oil play in the Penny area of 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:

Years ended December 31, ($ thousands)	2021	2020
Light oil	**$449,888**	$169,261
Heavy oil	**108,690**	2,857
Natural gas	**88,036**	34,011
Natural gas liquids	**51,958**	14,767
Oil and natural gas revenue	**$698,572**	$220,896
Processing income	**2,479**	1,177
Total revenue	**$701,051**	$222,073

Refer to note 5 for a listing of physical delivery contracts as at December 31, 2021.

Included in accounts receivable at December 31, 2021 was $71.7 million (December 31, 2020 - $24.2 million) of accrued production revenue. There were no significant adjustments for prior period accrued production revenue reflected in the current period. As at December 31, 2021, the Company did not have any contracts for the sale of its future production beyond one year in term.

7. Acquisitions:

The following table summarizes the Company's acquisitions for the years ended December 31, 2021 and 2020:

			Consideration	
CGU	Area	Acquisition date	Cash	Shares
Viking oil, Clearwater oil	Northern Clearwater, Eyehill	March 25, 2021	$102,610	$ –
Clearwater oil	Northern Clearwater	March 25, 2021	34,358	10,218
Charlie Lake oil	Charlie Lake	June 1, 2021	258,201	280,209
Clearwater oil	Southern Clearwater	August 31, 2021	35,727	–
Various	Other minor	Various	25,360	–
December 31, 2021			**$456,256**	**$290,427**
Clearwater oil	Northern Clearwater	December 21, 2020	$53,874	$ –
Clearwater oil	North and South Clearwater	December 21 2020	41,038	–
Various	Other minor	Various	3,899	–
December 31, 2020			$98,811	**$ –**

(a) 2021 Acquisitions

On March 25, 2021 the Company completed the Northern Clearwater, Eyehill oil acquisition that included assets in both the Nipisi and Provost fields for total cash consideration of $102.6 million. There were $0.7 million of transaction costs incurred by the Company expensed through earnings. The acquisition has been accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at the estimated fair value on the acquisition date of March 25, 2021. Assets acquired in this transaction will be included in the Clearwater oil CGU (Nipisi) and the Viking oil CGU (Provost). Assets held for sale relate to the sale of a gross overriding royalty ("GORR") on the Northern Clearwater Nipisi assets.

The determination of the purchase price, based on management's estimate of fair values, is as follows:

($ thousands)		Amount
Net assets acquired:		
Oil and natural gas interests	$	103,859
Assets held for sale		3,571
Decommissioning obligations		(4,820)
Net assets acquired	**$**	**102,610**
Purchase consideration:		
Cash	$	102,610
Total purchase consideration	**$**	**102,610**

The fair value of oil and natural gas interests has been estimated with reference to an internally prepared reserves evaluation for the acquired properties. The estimated proved and probable oil and natural gas reserves and related cash flows were discounted at a rate based on what a market participant would have paid as well as market metrics in the prevailing areas at the time. The fair value of decommissioning obligations was initially estimated using a credit adjusted risk-free rate of 8%.

Oil and natural gas revenue of $44.6 million and a net income of $10.2 million are included in the statements of income (loss) and comprehensive income (loss) for the Northern Clearwater, Eyehill acquisition assets since the closing date of March 25, 2021.

If the acquisition had occurred on January 1, 2021, the incremental oil and natural gas revenue and income recognized for the period ended December 31, 2021 and the pro forma results would have been as follows:

Period ended December 31, 2021 ($ thousands)	As stated	Northern Clearwater, Eyehill	*(unaudited)* Pro Forma
Oil and natural gas revenue	$698,572	$11,305	$709,877
Net income	$390,508	2,314	$392,822

(1) This pro-forma information is not necessarily indicative of results of operations that would have resulted had the Northern Clearwater, Eyehill oil acquisition been effective on the dates indicated or the results that may be obtained in the future.

On March 25, 2021 the Company completed the Northern Clearwater oil acquisition of assets in the Nipisi field for total cash consideration of $34.4 million including $0.9 million of capitalized transaction costs and the issuance of 4.9 million Common Shares of the Company. Based upon Tamarack's share price on the date of closing of $2.09 per common share, the total consideration was approximately $44.6 million. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets and liabilities based on their relative fair values at the date of acquisition. Assets acquired in this transaction will be included in the Clearwater oil CGU. Assets held for sale relate to the sale of a GORR on the Northern Clearwater Nipisi assets.

The amounts recognized on the date of acquisition of the identifiable net assets were as follows:

($ thousands)		Amount
Net assets acquired:		
Oil and natural gas interests	$	42,232
Assets held for sale		2,409
Decommissioning obligations		(65)
Net assets acquired	**$**	**44,576**
Purchase consideration:		
Cash consideration	$	34,358
Share consideration (4,888,889 common shares)		10,218
Total purchase consideration	**$**	**44,576**

For the year ended December 31, 2021, the Company disposed of a 4% GORR on a select portion of the Nipisi properties acquired in the March 25, 2021 Northern Clearwater, Eyehill and Northern Clearwater oil acquisitions for net proceeds of $13.5 million and recorded a gain on disposition of $7.5 million.

The Company acquired all of the issued and outstanding common shares of Anegada Oil Corp. (“Anegada”) on June 1, 2021 for total consideration of $538.4 million. The assets acquired from Anegada included certain oil and natural gas properties located in the Grande Prairie field in the Charlie Lake area . The acquisition was completed for total cash consideration of $258.2 million and the issuance of 105.3 million common shares of the Company at the date of closing share price of $2.66 per common share. The acquisition has been accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at the estimated fair value on the acquisition date of June 1, 2021. There were $7.4 million of transaction costs incurred by the Company and expensed through earnings. Assets acquired in this transaction will be included in the Charlie Lake oil CGU. Assets held for sale primarily relate to the sale of a GORR on the Charlie Lake (Grande Prairie) assets.

The determination of the purchase price, based on management’s estimate of fair values, is as follows:

($ thousands)		Amount
Net assets acquired:		
Oil and natural gas interests	$	677,740
Right-of-use assets		1,624
Current assets		21,097
Current liabilities		(10,451)
Lease liabilities		(1,624)
Risk management contracts		(9,610)
Bank debt		(37,734)
Assets held for sale		33,078
Decommissioning obligations		(6,072)
Deferred tax liability		(129,638)
Net assets acquired	**$**	**538,410**
Purchase consideration:		
Cash	$	258,201
Share consideration (105,341,880 common shares)		280,209
Total purchase consideration	**$**	**538,410**

For purposes of estimating the acquisition-date fair value of the oil and natural gas interests, the Company's internal reserves evaluator provided an estimate of proved and probable oil and natural gas reserves and the related cash flows. The estimated proved and probable oil and natural gas reserves and related cash flows were discounted at a rate based on what a market participant would have paid as well as market metrics in the prevailing areas at the time. The fair value of decommissioning obligations was initially estimated using a credit adjusted risk-free rate of 8%.

For the year ended December 31, 2021 the Company disposed of a 2% GORR on a select portion of the Charlie Lake area (Grande Prairie field) properties for net proceeds of $31.6 million.

Oil and natural gas revenue of $175.6 million and a net income of $53.6 million are included in the statements of income (loss) and comprehensive income (loss) for the Charlie Lake area acquisition assets since the closing date of June 1, 2021.

If the acquisition had occurred on January 1, 2021, the incremental oil and natural gas revenue and net income recognized for the period ended December 31, 2021 and the pro forma results would have been as follows:

Period ended December 31, 2021 ($ thousands)	**As stated**	**Charlie Lake area acquisition**	*(unaudited)* **Pro Forma**
Oil and natural gas revenue	$698,572	$83,269	$781,841
Net income	$390,508	$9,875	$400,383

(1) This pro-forma information is not necessarily indicative of results of operations that would have resulted had the Charlie Lake acquisition been effective on the dates indicated or the results that may be obtained in the future.

On August 31, 2021 the Company completed the Southern Clearwater oil acquisition of assets in the Jarvie field for total cash consideration of $35.7 million. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets and liabilities based on the relative fair values at the date of acquisition. Assets acquired in this transaction will be included in the Clearwater oil CGU.

The amounts recognized on the date of acquisition of the identifiable net assets were as follows:

($ thousands)		**Amount**
Net assets acquired:		
Oil and natural gas interests	$	37,039
Decommissioning obligations		(1,312)
Net assets acquired	**$**	**35,727**
Purchase consideration:		
Cash consideration	$	35,727
Total purchase consideration	**$**	**35,727**

For the year ended December 31, 2021 the Company executed other minor acquisitions in various CGUs and various fields for cash consideration of approximately $25.4 million. The Company applied the optional concentration test permitted under IFRS 3 to all of the other minor acquisitions which resulted in all of the other minor acquired assets being accounted for as asset acquisitions. As such the purchase price of the other minor acquisitions were allocated to the identifiable assets and liabilities based on their relative fair values at the dates of acquisitions.

(b) 2020 Acquisitions

On July 9, 2020, the Company completed the acquisition of certain light oil and liquids rich natural gas properties located in West Central Alberta. The assets were acquired for total cash consideration of $4.0 million including $0.1 million of capitalized transaction costs. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets and liabilities based on their relative fair values at the date of acquisition.

On December 21, 2020 the Company completed an acquisition of certain oil and gas properties located in the Northern Clearwater area of Alberta (Nipisi field) for total cash consideration of $53.9 million, including $1.1 million of capitalized transaction costs. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets and liabilities based on their relative fair values at the date of acquisition. Assets acquired in this transaction were included in the newly formed Clearwater oil CGU.

On December 21, 2020 the Company completed an acquisition of certain oil and gas properties located in the Northern Clearwater area of Alberta (Nipisi field) and the Southern Clearwater area of Alberta (Jarvie field) for total cash consideration of $41.0 million including $1.3 million of capitalized transaction costs. The Company applied the optional concentration test permitted under IFRS 3 to the acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets and liabilities based on their relative fair values at the date of acquisition. Assets acquired in this transaction were included in the newly formed Clearwater oil CGU.

For the year ended December 31, 2020 the Company disposed of a 2% GORR on a select portion of the Nipisi field and Jarvie field properties acquired in the December 21, 2020 Northern Clearwater and Southern Clearwater area oil acquisitions for proceeds of $15.5 million and recorded a gain on disposition of $10.7 million.

8. Property, plant and equipment:

($ thousands)	Oil and natural gas interests	Other assets	Total
Cost:			
Balance at December 31, 2019	$2,076,327	$1,995	$2,078,322
Right-of-use assets (note 13)	–	332	332
Property acquisitions (note 7)	111,339	–	111,339
Cash additions	102,691	284	102,975
Decommissioning costs	45,850	–	45,850
Stock-based compensation	897	–	897
Transfer from exploration and evaluation assets (note 10)	148	–	148
Balance at December 31, 2020	2,337,252	2,611	2,339,863
Right-of-use assets (note 13)	–	1,914	1,914
Acquisitions (note 7)	905,780	73	905,853
Cash additions	186,547	1,017	187,564
Decommissioning costs	23,573	–	23,573
Stock-based compensation	3,588	–	3,588
Transfer from exploration and evaluation assets (note 10)	532	–	532
Disposals	(65,733)	–	(65,733)
Balance at December 31, 2021	$3,391,539	$5,615	$3,397,154
Accumulated depletion, depreciation and impairment losses:			
Balance at December 31, 2019	$876,189	$1,183	$877,372
Depletion and depreciation	119,667	394	120,061
Impairment (note 9)	399,000	–	399,000
Balance at December 31, 2020	1,394,856	1,577	1,396,433
Depletion and depreciation	211,093	529	211,622
Disposals	(57,436)	–	(57,436)
Impairment reversal (note 9)	(390,000)	–	(390,000)
Balance at December 31, 2021	$1,158,513	$2,106	$1,160,619

	Oil and natural gas interests	Other assets	Total
Carrying amounts:			
At December 31, 2020	$942,396	$1,034	$943,430
At December 31, 2021	$2,233,026	$3,509	$2,236,535

(a) **Security:**

At December 31, 2021 and 2020, all of the Company's properties were pledged as security for the bank debt (note 16).

(b) **Contingencies:**

Although the Company believes that it has title to its oil and natural gas properties, it cannot control or completely protect itself against the risk of title disputes or challenges.

(c) **Dispositions:**

On September 9, 2021, Tamarack completed a non-cash asset swap transaction whereby the Company disposed of certain oil properties located in the Lochend and Harmattan areas of Alberta (Cardium oil CGU) and acquired certain oil properties in the Monarch area of Alberta (Penny oil CGU). The carrying value of the Lochend and Harmattan assets disposed, net of decommissioning obligations, was $6.9 million and the fair value of the Monarch net assets acquired was $7.8 million, resulting in a gain on the exchange of $0.9 million.

For the year ended December 31, 2021 the Company also disposed of non-core properties for proceeds of $1.2 million and recorded a gain on disposition of $0.3 million.

(d) **Other:**

The calculation of depletion at December 31, 2021 includes estimated future development costs of $965,626 (December 31, 2020 – $637,332) associated with the development of the Company's proved and probable oil and natural gas reserves and excludes salvage value of $89,442 (December 31, 2020 – $79,357).

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

($ thousands)	Processing facilities	Surface leases	Office leases	Total
Balance at December 31, 2019	$9,402	$1,736	$ –	$11,138
Lease additions	–	–	332	332
Depletion and depreciation	(1,366)	(150)	(145)	(1,661)
Impairment (note 9)	(3,123)	(308)	–	(3,431)
Balance at December 31, 2020	$4,913	$1,278	$187	$6,378
Lease additions	–	–	1,914	1,914
Leases acquired (note 7)	1,551	–	73	1,624
Depletion and depreciation	(1,782)	(144)	(474)	(2,400)
Impairment reversal (note 9)	2,225	–	–	2,225
Balance at December 31, 2021	$6,907	$1,134	$1,700	$9,741

9. Impairment and impairment reversal

The Company has considered the impact of the evolving worldwide demand for energy and global advancement of alternative sources of energy not sourced from fossil fuels in its assessment of impairment and impairment reversal on its oil and gas properties, both as possible indicators of impairment and impairment reversal, and as part of 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.

(a) **2021 assessment:**

At December 31, 2021 there were no indicators of impairment identified.

At both December 31, 2021 and June 30, 2021, the Company recorded reversals of prior impairment charges.

At December 31, 2021 there were indicators of reversal of impairment identified in the Company's Cardium oil CGU, Viking oil CGU and Penny oil CGU as a result of improved forward commodity prices for natural gas, condensate and oil associated with the proved and probable oil and natural gas reserves at December 31, 2021, and a resultant increase in proved and probable reserves as estimated in the Company's December 31, 2021 external independent qualified reserves evaluators report. The impairment reversal of $90.0 million was recorded as follows: the Cardium oil CGU reversed $14.3 million of historical impairment charges, the Viking oil CGU reversed $52.3 million of historical impairment charges and the Penny oil CGU reversed $23.4 million of historical impairment charges. The estimated recoverable amount of these CGUs as at December 31, 2021, net of decommissioning obligations, was $248.6 million for the Cardium oil CGU, $692.5 million for the Viking oil CGU and $83.4 million for the Penny oil CGU. The Viking oil CGU and Penny oil CGU have fully reversed all previous historical impairment charges, net of notional depletion. The estimated recoverable amount of the CGUs was based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator at December 31, 2021 at discount rates specific to the underlying composition of reserve categories of 12% to 25% (level 3 inputs). The estimated recoverable amounts of the CGUs were determined using the FVLCD methodology based on what Tamarack estimates it could receive for the assets in these CGUs if it disposed of them in the current environment taking into account higher commodity prices. The impairment reversal of $90.0 million was allocated to property, plant and equipment in the amount of $89.5 million and $0.5 million was allocated to the right-of-use assets.

The result of Tamarack's impairment reversal tests are sensitive to changes in forecasted oil and natural gas commodity prices, forecasted production, forecasted production costs, forecasted royalty costs, forecasted future development costs and discount rates. As such, any changes to these significant assumptions and estimates could decrease or increase the estimated recoverable amounts of the CGUs.

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

As at December 31, 2021, all else being equal, a 1% change in the discount rate would result in a change to impairment reversal of $8.5 million, a $1.00/bbl Cdn change to oil prices would result in a change to impairment reversal of approximately $5.5 million, and a $0.10/mmbtu Cdn change to natural gas prices would result in a change to impairment reversal of $5.9 million to the Cardium oil CGU. The impairment reversal recorded for the Viking oil CGU and Penny oil CGU, for which all previous impairment, net of depletion, has been reversed, would not change based on altering the inputs noted above.

The following forecasted oil and natural gas commodity price assumptions were used in determining whether a reversal of impairment to the carrying value of the CGUs existed at December 31, 2021, as forecasted by the external independent qualified reserves evaluator based on an average of those used by three external independent qualified reserves evaluator companies:

	2022	2023	2024	2025	2026	2027	2028	2029	Thereafter
Exchange rate (US$/Cdn$)(1)	0.7967	0.7967	0.7967	0.7967	0.7967	0.7967	0.7967	0.7967	0.7967
WTI (US$/bbl)(1)	72.83	68.78	66.76	68.09	69.45	70.84	72.26	73.70	+2.0%/yr
Edmonton Par (Cdn$/bbl)(1)	86.82	80.73	78.01	79.57	81.16	82.78	84.44	86.13	+2.0%/yr
AECO (Cdn$/MMbtu)(1)	3.56	3.20	3.05	3.10	3.17	3.23	3.30	3.36	+2.0%/yr

(1) Forecasted oil and natural gas commodity price, effective January 1, 2022.

At June 30, 2021, there were indicators of reversal of impairment identified in the Company's Cardium oil CGU and Viking oil CGU as a result of improved forward commodity prices for natural gas, condensate and oil associated with the proved and probable oil and natural gas reserves at June 30, 2021. The impairment reversal of $300.0 million was recorded as follows: the Cardium oil CGU reversed $140.0 million of historical impairment charges and the Viking oil CGU reversed $160.0 million of historical impairment charges. The estimated recoverable amount of these CGUs as at June 30, 2021, net of decommissioning obligations, was $257.2 million for the Cardium oil CGU and $643.8 million for the Viking oil CGU based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator at December 31, 2020 and updated by the Company's internal reserves evaluator to June 30, 2021 for production, production costs, royalty costs, future development costs and forecasted oil and natural gas commodity prices as at that date at discount rates specific to the underlying composition of reserve categories of 10% to 25% (level 3 inputs). The estimated recoverable amounts of the CGUs were determined using the FVLCD methodology based on what Tamarack estimates it could receive for the assets in these CGUs if it disposed of them in the current environment taking into account higher oil and natural gas commodity prices. The impairment reversal of $300.0 million was allocated to property, plant and equipment in the amount of $298.3 million and $1.7 million was allocated to the right-of-use assets.

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

The following forecasted oil and natural gas commodity price assumptions were used in determining whether a reversal of impairment to the carrying value of the CGUs existed at June 30, 2021, as forecasted by the external independent qualified reserves evaluator based on an average of those used by three external independent qualified reserves evaluator companies:

	2021	2022	2023	2024	2025	2026	2027	2028	Thereafter
Exchange rate (US$/Cdn$)(1)	0.8033	0.8017	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000	0.8000
WTI (US$/bbl)(1)	71.33	67.20	63.95	63.23	64.50	65.79	67.10	68.44	+2.0%/yr
Edmonton Par (Cdn$/bbl)(1)	83.20	78.27	74.06	73.05	74.51	76.00	77.52	79.07	+2.0%/yr
AECO (Cdn$/MMbtu)(1)	3.46	3.13	2.72	2.71	2.76	2.82	2.88	2.94	+2.0%/yr

(1) Forecasted oil and natural gas commodity price, effective July 1, 2021.

The Company has recorded an aggregate impairment reversal of $390.0 million for the year ended December 31, 2021 of which $154.3 million related to the Cardium oil CGU, $212.3 million related to the Viking oil CGU and $23.4 million related to the Penny oil CGU. The aggregate impairment reversal was allocated to property, plant and equipment in the amount of $387.8 million and $2.2 million was allocated to right-of-use assets.

(b) **2020 assessment:**

The Company determined that there were no external or internal indicators of impairment or historical impairment reversal at December 31, 2020 for the Viking oil, Cardium oil, minor gas and Clearwater oil CGUs and no impairment tests were required. However, there were indicators of impairment for the Penny oil CGU.

At December 31, 2020, an impairment charge of $18.0 million was recorded as a result of a decrease in the current quantities of recoverable proved and probable oil and natural gas reserves at the Company’s Penny oil CGU. The estimated recoverable amount of this CGU as at December 31, 2020, net of decommissioning obligations, was estimated to be $62.0 million based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company’s external independent qualified reserves evaluator at discount rates specific to the underlying composition of reserve categories of 12% to 25% (level 3 inputs). The estimated recoverable amount of the Penny oil CGU was determined using the FVLCD methodology based on what Tamarack could receive for the assets in this CGU if it disposed of them in the current environment taking into account lower oil and natural gas commodity prices.

The results of Tamarack’s impairment tests are sensitive to changes in forecasted oil and natural gas commodity prices; forecasted production; forecasted production costs; forecasted royalty costs; forecasted future development costs and discount rates. As such, any changes to these significant assumptions and estimates could decrease or increase the estimated recoverable amounts of the CGUs and result in impairment charges or in the reversal of historical impairment charges.

As at December 31, 2020, all else being equal, a 1% change in the discount rate would result in a change to impairment of approximately $3.2 million to the Penny oil CGU, a $1.00/bbl Cdn change to oil prices would result in a change to impairment of approximately $2.5 million to the Penny oil CGU.

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

The following forecasted oil and natural gas commodity price assumptions were used in determining whether an impairment to the carrying value of the CGUs existed at December 31, 2020, as forecasted by the external independent qualified reserves evaluator based on an average of those used by three external independent qualified reserves evaluator companies:

	2021	2022	2023	2024	2025	2026	2027	2028	Thereafter
Exchange rate (US$/Cdn$)(1)	0.7683	0.7650	0.7633	0.7633	0.7633	0.7633	0.7633	0.7633	0.7633
WTI (US$/bbl)(1)	47.17	50.17	53.17	54.97	56.07	57.19	58.34	59.50	+2.0%/yr
Edmonton Par (Cdn$/bbl)(1)	55.76	59.89	63.48	65.76	67.13	68.53	69.95	71.40	+2.0%/yr
AECO (Cdn$/mmbtu)(1)	2.78	2.70	2.61	2.65	2.70	2.76	2.81	2.86	+2.0%/yr

(1) Forecasted oil and natural gas commodity price, effective January 1, 2021.

At March 31, 2020 an impairment charge of $381.0 million was recorded as a result of a decrease in current and forecasted oil and natural gas commodity prices. The impairment recognized relates to the Company's CGUs as follows: the Viking oil CGU was impaired $235.0 million, the Cardium oil CGU was impaired $137.0 million, the Penny oil CGU was impaired $7.0 million and the minor gas CGU was impaired $2.0 million. The estimated recoverable amount of these CGUs as at March 31, 2020, net of decommissioning obligations, was $447.9 million for the Viking oil CGU, $137.9 million for the Cardium oil CGU, $81.4 million for the Penny oil CGU and ($11.1) million for the minor gas CGU based on the net present value of before tax cash flows from proved and probable oil and natural gas reserves estimated by the Company's external independent qualified reserves evaluator at December 31, 2019 and updated by the Company's internal reserves evaluator to March 31, 2020 for production, production costs, royalty costs, future development costs and forecasted oil and natural gas commodity prices as at that date at discount rates specific to the underlying composition of reserve categories of 10% to 20% (level 3 inputs). The estimated recoverable amounts of the CGUs were determined using the FVLCD methodology based on what Tamarack estimates it could receive for the assets in these CGUs if it disposed of them in the current environment taking into account lower oil and natural gas commodity prices. The impairment charge of $381.0 million was allocated to property, plant and equipment in the amount of $377.6 million and $3.4 million was allocated to the right-of-use asset.

The results of Tamarack's impairment tests are sensitive to changes in forecasted oil and natural gas commodity prices, forecasted production, forecasted production costs, forecasted royalty costs, forecasted future development costs and discount rates. As such, any changes to these significant assumptions and estimates could decrease or increase the estimated recoverable amounts of the CGUs and result in impairment charges or in the reversal of historical impairment charges.

As at March 31, 2020, all else being equal, a 1% change in the discount rate, a $1.00/bbl Cdn change to oil prices and a $0.10/mmbtu Cdn change to natural gas prices would result in the following changes to the impairment charge recognized:

Impairment expense ($ millions)	1% change in discount rate	$1.00 Cdn change in oil price	$0.10/mmbtu Cdn change in gas price
Viking oil CGU	$15.9	$17.1	$2.9
Cardium oil CGU	7.9	5.9	5.5
Penny oil CGU	4.1	3.1	0.3
Minor gas CGU	0.3	0.4	0.4
Total	$28.2	$26.5	$9.1

The following forecasted oil and natural gas commodity price assumptions were used in determining whether an impairment or reversal of impairment to the carrying value of the CGUs existed at March 31, 2020, as forecasted by the external independent qualified reserves evaluator based on an average of those used by three external independent qualified reserves evaluator companies:

	2020	2021	2022	2023	2024	2025	2026	2027	Thereafter
Exchange rate (US$/Cdn$)(1)	0.7067	0.7283	0.7450	0.7467	0.7483	0.7500	0.7500	0.7500	0.7500
WTI (US$/bbl)(1)	29.17	40.45	49.17	53.28	55.66	56.87	58.01	59.17	+2.0%/yr
Edmonton Par (Cdn$/bbl)(1)	29.22	46.85	59.27	65.02	68.43	69.81	71.24	72.70	+2.0%/yr
AECO (Cdn$/mmbtu)(1)	1.74	2.20	2.37	2.45	2.52	2.60	2.66	2.72	+2.0%/yr

(1) Forecasted oil and natural gas commodity price, effective April 1, 2020.

The Company recorded an aggregate impairment charge of $399.0 million for the year ended December 31, 2020 of which $235.0 million related to the Viking oil CGU, $137.0 million related to the Cardium oil CGU, $25.0 million related to the Penny oil CGU, and $2.0 million related to the minor gas CGU. The aggregate impairment was allocated to property, plant and equipment in the amount of $395.6 million and $3.4 million was allocated to right-of-use assets.

10. Exploration and evaluation assets:

($ thousands)	Total
Cost:	
Balance at December 31, 2019	$25,854
Additions	568
Transfer to property, plant and equipment (note 8)	(148)
Balance at December 31, 2020	26,274
Additions	3,595
Disposal (note 8)	(3,169)
Transfer to property, plant and equipment (note 8)	(532)
Balance at December 31, 2021	$26,168
Accumulated amortization and impairment:	
Balance at December 31, 2019	$24,217
Amortization	597
Balance at December 31, 2020	24,814
Amortization	715
Disposal (note 8)	(3,169)
Balance at December 31, 2021	$22,360

	Total
Carrying amounts:	
At December 31, 2020	$1,460
At December 31, 2021	$3,808

11. 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 $273.4 million at December 31, 2021 (December 31, 2020 – $233.9 million), which is expected to be incurred between 2022 and 2050. A risk-free rate of 1.7% (December 31, 2020 – 1.2%) and an inflation rate of 1.8% (December 31, 2020 – 1.5%) is used to calculate the present value of the decommissioning obligations at December 31, 2021 as presented in the table below:

($ thousands)	December 31, 2021	December 31, 2020
Balance, beginning of the year	**$245,437**	$184,846
Liabilities incurred	**8,955**	3,839
Liabilities acquired (note 7)	**21,702**	17,388
Change in estimates	**(3,687)**	20,051
Change in discount rate on acquisition	**18,305**	21,960
Expenditures	**(4,466)**	(3,825)
Site rehabilitation program grant (note 21)	**(5,365)**	(1,395)
Liabilities disposed	**(1,304)**	–
Accretion (note 17)	**4,895**	2,573
Balance, end of the year	**$284,472**	$245,437

Revisions due to the change of discount rate on acquisitions of $18.3 million results from the difference between the fair value discount rate on the acquisition date and the subsequent revaluation using the risk-free rate.

The change in estimate for the year ended December 31, 2021 resulted from decommissioning obligations being revalued using a risk-free rate of 1.7% and an inflation rate of 1.8% as opposed to a risk-free rate of 1.2% and an inflation rate of 1.5% used at December 31, 2020.

During the year ended December 31, 2021, approximately $5.4 million (December 31, 2020 – $1.4 million) was granted and paid through the SRP and ASCP programs to pay service companies to complete abandonment and reclamation work.

Timing of decommissioning obligation expenditures expected to be incurred are:

($ thousands)	As at December 31, 2021
Decommissioning obligations – Less than 1 year	$5,298
Decommissioning obligations – Greater than 1 year	279,174
Total	$284,472

12. Personnel expenses:

The aggregate payroll expense of employees and executive management was as follows:

Years ended December 31, ($ thousands)	**2021**	2020
Wages and salaries	**$14,270**	$8,495
Government emergency wage subsidy	**–**	(1,321)
Benefits and other personnel costs	**2,221**	1,748
Stock-based compensation	**9,088**	5,818
Total employee remuneration	**25,579**	14,740
Capitalized portion of total remuneration	**(9,459)**	(4,847)
	$16,120	$9,893

Personnel expenses directly attributed to capital activities have been capitalized and included in property, plant and equipment.

In addition to their salaries, the Company also provides cash and non-cash benefits to executive officers and employees. The executive officers include the President and Chief Executive Officer, the VP Finance and Chief Financial Officer, the Chief Operating Officer, the VP Engineering, the VP Production and Operations, the VP Exploration and the VP Corporate Planning and Business Development. Executive officers, employees and directors may also participate in the Company's stock option and performance and restricted share unit program. Key executive officers' and directors' compensation is comprised of the following:

Years ended December 31, ($ thousands)	2021	2020
Salaries, wages and short-term benefits	**$5,180**	$4,218
Stock-based compensation [1]	**6,014**	4,239
	$11,194	$8,457

(1) Represents the amortization of stock-based compensation associated with restricted share units, performance share units and stock options granted to executive officers and directors as recorded in the financial statements. Stock based compensation for 2021 also includes the settlement of preferred shares in the amount of $840.

13. Lease liabilities:

The Company has lease liabilities for contracts related to financing facilities, surface leases and the Company's head office lease. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. Discount rates used during the year ended December 31, 2021 were between 4.0% and 8.8%, depending on the duration of the lease. The following table summarizes lease liabilities at December 31, 2021:

Years ended December 31, ($ thousands)	2021	2020
Balance, beginning of the year	**$10,154**	$12,170
Lease additions	**1,914**	332
Leases acquired (note 7)	**1,624**	–
Interest expense	**791**	840
Lease payments	**(3,951)**	(3,188)
Balance, end of the year	**$10,532**	$10,154
Current portion	**$3,600**	$2,484
Long term portion	**$6,932**	$7,670

Undiscounted cash outflows relating to the lease liabilities are:

Years ended December 31, ($ thousands)	2021	2020
Less than 1 year	**$4,099**	$3,155
Years 2 and 3	**6,369**	6,140
Years 4 and 5	**2,414**	3,110
Thereafter	**1,745**	2,309
Total	**$14,627**	$14,714

The expense recognized relating to short-term leases and leases of low-value assets for the year ended December 31, 2021 was $0.1 million (December 31, 2020 - $0.1 million) and have been included in production expenses.

14. Supplemental cash flow information:

Changes in non-cash working capital consists of:

Years ended December 31, ($ thousands)	2021	2020
Source/(use) of cash:		
Accounts receivable	**$(49,123)**	$11,438
Prepaid expenses and deposits	**(6,564)**	659
Accounts payable and accrued liabilities	**33,285**	1,094
Working capital acquired (note 7)	**10,646**	–
	$(11,756)	$13,191
Related to operating activities	**$(29,789)**	$6,367
Related to financing activities	**$(2,105)**	$1,556
Related to investing activities	**$20,138**	$5,268

The following are included in cash provided by operating activities:

Years ended December 31, ($ thousands)	2021	2020
Interest paid in cash on bank debt	**$18,334**	$8,611
Bank renewal fees	**2,359**	673
Interest paid on lease liabilities	**791**	840

The table below reconciles the movements of financial liabilities to cash flows arising from financing activities:

($ thousands)	Lease liabilities	Bank debt
Balance at January 1, 2020:	$12,170	$192,907
Changes from financing cash flows:		
Payment of lease liabilities	(2,348)	–
Draw on bank debt	–	16,701
Other changes:		
Interest expense	840	–
Lease additions	332	–
Interest paid	(840)	–
Unrealized gain on foreign exchange	–	1,249
Balance at December 31, 2020	$10,154	$210,857
Changes from financing cash flows:		
Payment of lease liabilities	**(3,160)**	–
Draw on bank debt	–	**265,314**
Other changes:		
Interest expense	**791**	–
Lease additions	**1,914**	–
Lease acquired (note 7)	**1,624**	–
Interest paid	**(791)**	–
Unrealized loss on foreign exchange	**–**	**1,266**
Balance at December 31, 2021	**$10,532**	**$477,437**

15. Income taxes:

The tax provision differs from the amount computed by applying the combined Canadian federal and provincial statutory income tax rates to loss before taxes as follows:

Years ended December 31, ($ thousands)	2021	2020
Income (loss) before taxes	**$519,766**	$(398,928)
Expected tax rate	**23.18%**	24.00%
Expected income tax recovery (expense)	**(120,482)**	95,743
Change in unrecognized deferred tax assets	**(7,283)**	(4,148)
Stock-based compensation	**(1,384)**	(1,320)
Change in rates and other	**(109)**	(2,731)
Deferred income tax recovery (expense)	**$(129,258)**	$87,544

In 2021, the blended statutory tax rate was 23.18% (December 31, 2020 – 24.00). Effective July 1, 2020, the Government of Alberta accelerated the general corporate tax rate reduction to 8%.

Deferred tax assets and liabilities are attributable to the following:

Years ended December 31, ($ thousands)	2021	2020
Deferred tax liabilities:		
Property, plant and equipment	**$(308,451)**	$(66,163)
Deferred tax assets:		
Financial instruments and foreign exchange	**3,021**	2,331
Non-capital losses	**27,526**	54,439
Share issue costs	**1,223**	287
Lease liabilities	**2,544**	2,336
Decommissioning obligations	**65,793**	56,453
Total	**$(208,344)**	$49,683

In calculating the deferred income tax liability in 2021, the Company included $123.0 million (December 31, 2020 - $237.1 million) of non-capital losses available for carry forward to reduce taxable income in future years. These losses expire between 2029 and 2039.

Deferred tax assets have not been recognized in respect of the following item:

Years ended December 31, ($ thousands)	2021	2020
Property, plant and equipment	**$48,271**	$37,459

A continuity of the net deferred tax asset (liability) is detailed in the following tables:

($ thousands)	Balance January 1, 2020	Recognized in equity	Recognized in business combinations	Recognized in profit or loss	Other	Balance December 31, 2020
Property, plant and equipment	$(126,622)	$ –	$ –	$60,459	$ –	$(66,163)
Lease liabilities	2,921	–	–	(585)	–	2,336
Non-capital losses	39,797	–	–	14,642	–	54,439
Decommissioning obligations	44,363	–	–	12,090	–	56,453
Share issue costs	320	368	–	(401)	–	287
Financial instruments and foreign exchange	992	–	–	1,339	–	2,331
Total	$(38,229)	$ 368	$ –	$87,544	$ –	$49,683

($ thousands)	Balance January 1, 2021	Recognized in equity	Recognized in business combinations	Recognized in profit or loss	Other	Balance December 31, 2021
Property, plant and equipment	$(66,163)	$ –	$(133,619)	$(108,669)	$ –	$(308,451)
Lease liabilities	2,336	–	374	(166)	–	2,544
Non-capital losses	54,439	–	–	(26,913)	–	27,526
Decommissioning obligations	56,453	–	1,397	7,943	–	65,793
Share issue costs	287	869	–	67	–	1,223
Financial instruments and foreign exchange	2,331	–	2,210	(1,520)	–	3,021
Total	$49,683	$ 869	$(129,638)	$(129,258)	$ –	$(208,344)

16. Bank debt:

Tamarack currently has available a Sustainability Linked Lending revolving credit facility in the amount of $550 million and an operating facility of $50 million (collectively, the “SLL Facility”) with a syndicate of lenders.

The Company’s existing credit facility was amended to include sustainability-linked incentive pricing terms in the recently completed SLL Facility Amended and Restated Credit Agreement (“ARCA”). Additionally, the ARCA eliminated the term credit facility and the Consolidated Net Debt to Cash Flow Ratio financial covenant and added a Consolidated Senior Debt-to-Consolidated EBITDA ratio interest rate determination.

The total interest rate on the SLL Facility is determined through a pricing grid that categorizes based on both a total amount drawn, and a Consolidated Senior Debt-to-Consolidated EBITDA Ratio as defined in the SLL Facility ARCA. The interest rate will vary depending on: the lending vehicle employed; the total loan value drawn; and the Company’s Consolidated Senior Debt-to-Consolidated EBITDA ratio. The ARCA defines: (i) Consolidated Senior Debt to Consolidated EBITDA Ratio as the ratio of Consolidated Senior Debt at the end of the Fiscal Quarter to Consolidated EBITDA for the Consolidated EBITDA period; (ii) Consolidated Senior Debt as Consolidated Debt; and (iii) Consolidated EBITDA as determined in accordance with IFRS as Net Income plus interest expense, plus the provision for income taxes, plus or minus all non-cash items, plus one-time transaction costs and fees relating to acquisitions, dispositions, equity offerings and other similar transactions, plus or minus losses and or gains from asset sales, plus or minus losses or earnings attributable to extraordinary and non-recurring items and less any cash payments related to prior periods included or deducted in determining Net Income. The Consolidated EBITDA period as at December 31, 2021 is the most recent quarter annualized.

Interest on bankers' acceptances ("BA") and LIBOR (or LIBOR Benchmark Replacement) based loans ("LIBOR") will vary based on a BA/LIBOR pricing grid from a low of the banks' posted rates plus 2.75% to a high of the banks' posted rates plus 4.75%. Interest on prime lending varies based on a prime rate pricing grid from a low of the banks' prime rates plus 1.75% to a high of the banks' prime rates plus 3.75%. The standby fee for the SLL Facility will vary as per a pricing grid from a low of 0.69% to a high of 1.19% on the undrawn portion of the SLL Facility. The lending vehicles that Tamarack employs will vary from time to time based on capital needs and current market rates.

The LIBOR benchmark transition begins on December 31, 2021 with certain tenors of the U.S. dollar LIBOR benchmark no longer published as of that date. Certain other tenors will continue to be published through mid-2023. As per the ARCA the LIBOR benchmark will be replaced by the secured overnight financing rate ("SOFR") as published by the Federal Reserve Bank of New York. We do not expect this change to have a material impact to Tamarack under the SLL Facility as U.S. dollar borrowings under the SLL facility can also bear interest at the banks' U.S. prime rates.

The SLL Facility incorporates sustainability-linked incentive pricing terms. The SLL Facility incorporates three of Tamarack's long-term goals as key performance indicators ("KPIs") and has structured them into sustainability performance targets ("SPTs"), that will decrease Tamarack's cost of borrowing by up to five basis points if the SPTs are achieved or increase Tamarack's cost of borrowing by up to five basis points in the event SPTs are missed. The SPTs include:

- Greenhouse Gas Emissions Intensity: 40% reduction in Scope 1 and 2 emissions by 2025 over the 2020 baseline, with a significant decrease in 2021 and more ratable 5% decreases through 2022 to 2025. This SPT exceeds the previous set target due to 2021 acquisitions and positive progress in emissions reductions to date.
- Decommissioning Management: committed annual capital investment in abandonment, remediation and reclamation activities at 150% of the Alberta Energy Regulator inventory reduction voluntary closure program targets. This target is equivalent to ~4.33% of inactive liabilities in 2021 with a 5% annual escalation.
- Indigenous Workforce Participation: target workforce representation of 6% or greater by 2025 with annual milestones and minimum of two additions each year.

As at December 31, 2021, the SLL Facility was secured by a $1.2 billion supplemental debenture with a floating charge over all assets. As the available lending limits of the SLL Facility are based on the lenders' interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review.

A total of $477.4 million was drawn as of December 31, 2021 (December 31, 2020 – $210.9 million). The interest rate applicable to the drawn amounts as of this date was 3.37%. The SLL Facility will be subject to its next extension by May 31, 2022, and if not extended by that date, will cease to revolve and all outstanding balances will become repayable one year from that date.

The Company manages its SLL Facility using a combination of prime rate loans, BA notes and US dollar denominated LIBOR loans. During the quarter ended December 31, 2021, concurrent with the drawdown of US dollar LIBOR loans, the Company entered into cross-currency swaps ("CCS") to fix the foreign exchange on US dollar LIBOR loan amounts for purposes of interest and principal repayments. At December 31, 2021, the Company had drawn US$235.0 million, fixed at notional amounts of $297.5 million through CCS maturing across the month of January 2022 (December 31, 2020 – the Company had drawn US$111.0 million, fixed at notional amounts of $142.8 million through various CCS).

17. Finance expenses:

Years ended December 31, ($ thousands)	**2021**	2020
Interest on bank debt	**$20,693**	$9,284
Interest expense on lease liabilities	**791**	840
Unrealized loss on foreign exchange	**1,266**	1,249
Unrealized gain on cross-currency swap	**(1,305)**	(1,311)
Accretion of decommissioning obligations	**4,895**	2,573
	$26,340	$12,635

18. Shareholders' equity:

a) Share capital:

At December 31, 2021 and 2020 the Company was authorized to issue an unlimited number of common shares ("Common Shares") and preferred shares without nominal or par value.

		2021		2020
($ thousands)	**Number**	**Amount**	Number	Amount
Balance, January 1	262,776,395	$876,124	222,793,117	$832,799
Issue of common shares - cash	33,333,300	75,000	40,925,000	47,064
Issue of common shares - acquisitions	110,230,769	290,427	–	–
Issue of common shares - cash on stock options	481,667	1,623	–	–
Issue of common shares - RSU and PSU exercise	4,047,343	–	3,363,378	–
Issue on settlement of preferred shares	307,025	1,104	–	–
Purchase of common shares - cancellation	–	–	(664,100)	(2,551)
Purchase of common shares - RSU and PSU exercise	(4,238,400)	–	(3,641,000)	–
Transfer on stock option exercise	–	1,023	–	–
Share issue costs, net of tax (2021 - $869; 2020 - $368)	–	(2,909)	–	(1,188)
Balance, December 31	406,938,099	$1,242,392	262,776,395	$876,124

No preferred shares have been issued.

b) Normal course issuer bid:

The Company announced on November 1, 2021 that the Toronto Stock Exchange had accepted the Company's intention to recommence the NCIB that was previously suspended on April 7, 2020. Pursuant to the NCIB, the Company is permitted to purchase up to 20.4 million Common Shares over a period of twelve months commencing on November 3, 2021. During the year ended December 31, 2021, the Company did not purchase and cancel any Common shares.

During the year ended December 31, 2020, the Company purchased and cancelled 0.7 million Common Shares at an average price of $1.94 per Common Share, for a total repurchase cost of $1.3 million. The Company suspended the NCIB as at April 7, 2020 due to the COVID-19 pandemic.

c) Treasury shares:

During the year ended December 31, 2021, the Company spent $13.0 million to purchase 4.2 million Common Shares to be used to settle stock options (“Stock Options”), restricted share units (“RSUs”) and performance share units (“PSUs”) on the date of exercise. As at December 31, 2021, 937,799 Common Shares remain classified as treasury shares to be used for future settlements of Stock Options, RSUs and PSUs.

During the year ended December 31, 2020, the Company spent $3.9 million to purchase 3.6 million Common Shares to be used to settle restricted share units (“RSUs”) on the date of exercise. As at December 31, 2020, 746,742 Common Shares remain classified as treasury shares to be used for future settlements.

19. Net income (loss) per share:

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

($ thousands, except per share amounts)	2021	2020
Net income (loss)	**$390,508**	$(311,384)
Weighted average shares - basic	**353,642**	222,781
Weighted average shares - diluted	**360,779**	222,781
Net income (loss) per share-basic	**$ 1.10**	$(1.40)
Net income (loss) per share-diluted	**$ 1.08**	$(1.40)

Per share amounts have been calculated using the weighted average number of Common Shares outstanding. For the year ended December 31, 2021, 10.6 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, respectively. For the year ended December 31, 2020, 11.5 million Common Shares issuable upon the exercise and/or settlement of Stock Options, RSUs, PSUs and TAC Preferred Shares were excluded from the diluted weighted average number of Common Shares outstanding as they were anti-dilutive due to the net loss.

20. Share-based payments:

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

Years ended December 31, ($ thousands)	2021	2020
Non-cash stock- based compensation		
Stock Options	**$595**	$285
RSUs	**3,512**	3,525
PSUs	**4,611**	2,587
Non-cash stock-based compensation:	**$8,718**	$6,397
Preferred share settlement	**840**	–
Total capitalized costs	**(3,588)**	(897)
Total expensed non-cash stock-based compensation	**5,970**	5,500

(a) **Preferred share plan:**

At December 31, 2021, there are no (December 31, 2020 – 740,307) preferred shares of Tamarack Acquisition Corp. (the "TAC Preferred Shares") issued and outstanding. The Company settled the TAC Preferred Shares by issuing 307,025 Common Shares and a payment of $0.1 million during the fourth quarter of 2021 in connection with the amalgamation of Tamarack Acquisition Corp. into Tamarack Valley Energy Ltd. on January 1, 2022, resulting in $0.8 million of additional compensation expense as the amount settled was in excess of the fair value of the preferred shares.

(b) **Options:**

Pursuant to the Company's stock option plan (the "Stock Option Plan") and the Company's performance and restricted share unit plan (the "PRSU Plan"), the Company may grant up to an aggregate of 28.5 million Stock Options, RSUs and PSUs to officers, employees, directors and consultants of the Company or its subsidiaries, as applicable. As at December 31, 2021, there was an aggregate of 11.7 million Stock Options, RSUs and PSUs issued and outstanding.

Stock Options issued under the Stock Option Plan do not have an exercise price of less than the market price of the Common Shares at the time of grant, do not exceed a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were 0.9 million Stock Options granted during the year ended December 31, 2021 (December 31, 2020 – 0.6 million).

The fair value of each Stock Option granted during the years ended December 31, 2021 and 2020 was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value and weighted average assumptions used to fair value the options are as follows:

	2021	2020
Risk free rate (%)	**0.85**	**0.71**
Expected volatility (%)	**61**	**51**
Expected life (years)	**5**	**5**
Forfeiture rate (%)	**–**	**–**
Dividend ($ per share)	**–**	**–**
Fair value at grant date ($ per option)	**1.21**	**0.49**

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, 2020	2,193	$3.01
Granted	559	1.13
Forfeited/expired	(848)	2.88
Outstanding, December 31, 2020	1,904	$2.51
Granted	868	2.33
Exercised	(482)	3.37
Forfeited/expired	(148)	2.85
Outstanding, December 31, 2021	**2,142**	**$2.22**

The range of exercise prices of the Stock Options outstanding and exercisable at December 31, 2021 is as follows:

	Stock Options outstanding			Stock Options exercisable	
Range of exercise price	Number outstanding (thousands)	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable (thousands)	Weighted average exercise price
$ 0.64 – 2.50	1,203	$1.75	3.8	186	$1.13
$ 2.51 – 2.81	659	$2.60	2.5	386	$2.60
$ 2.82 – 3.44	280	$3.37	0.1	280	$3.37
$ 0.64 – 3.44	**2,142**	**$2.22**	**2.9**	**852**	**$2.53**

(c) **RSUs:**

The PRSU Plan allows the Board of Directors to grant RSUs to officers, employees, consultants and non-employee directors of the Company or its subsidiaries. Each RSU entitles the holder to an award value to be paid as to one-third on each of the first, second and third anniversaries of the date of grant. There were 2.2 million RSUs granted during the year ended December 31, 2021 (December 31, 2020 – 2.0 million).

For the purpose of calculating stock-based compensation, the fair value of each RSU is determined at the grant date using the closing price of the Common Shares. On the date of exercise, the Company has the option of settling the RSU value in cash or in Common Shares of the Company.

The following table summarizes information about the RSUs:

	Number of RSUs (thousands)
Outstanding, January 1, 2020	6,987
Granted	1,986
Exercised	(3,363)
Forfeited	(245)
Outstanding, December 31, 2020	5,365
Granted	2,186
Exercised	(2,724)
Forfeited	(123)
Outstanding, December 31, 2021	**4,704**
Exercisable, December 31, 2021	**794**

(d) PSUs:

The PRSU Plan allows the Board of Directors to grant PSU awards to officers, employees and consultants of the Company or its subsidiaries. Each PSU entitles the holder to an award value on the third anniversary of the date of grant multiplied by a payout multiplier ranging from 0 to 2.0 times. The payout multiplier for performance-based awards will be determined by the Board of Directors based on an assessment of the Company's achievement of predefined corporate performance measures in respect of the applicable period. There were 2.9 million PSUs awarded during the year ended December 31, 2021 (December 31, 2020 – 1.7 million).

For the purpose of calculating stock-based compensation, the fair value of each award is determined at the grant date using the closing price of the Common Shares. On the date of exercise, the Company has the option of settling the PSU value in cash or in Common Shares of the Company.

The following table summarizes information about the PSU awards:

	Number of PSU awards (thousands)
Outstanding, January 1, 2020	2,157
Awarded	1,657
Forfeited	(250)
Outstanding, December 31, 2020	3,564
Awarded	2,918
Exercised	(1,323)
Forfeited	(285)
Outstanding, December 31, 2021	**4,874**
Earned, December 31, 2021	**1,593**
Exercisable, December 31, 2021	**–**

21. Government assistance:

As at December 31, 2021 the Company has recorded $5.2 million of combined ERF and MTIP funding, of which $1.1 million is repayable under the terms of the ERF agreement, related to the Company's construction of a methane conservation program in the Nipisi field of Alberta. The ERF agreement includes scheduled repayments for the repayable funding on March 31, 2025, March 31, 2026 and March 31, 2027 (see note 22). The Company has recorded $5.4 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 consolidated statement of income (loss) and comprehensive income (loss) for the year ended December 31, 2021 (December 31, 2020 - $1.4 million). The Company has not received any CEWS payments and has not recognized any reduction to general and administrative expense for the year ended December 31, 2021 (December 31, 2020 - $1.3 million).

22. Commitments:

The following table summarizes the Company's commitments as at December 31, 2021:

($ thousands)	2022	2023	2024	2025	2026+
Bank debt(1)	–	477,437	–	–	–
Lease(2)	328	347	347	261	–
Government loan(3)	–	–	–	471	629
Take or pay commitments(4)	4,023	3,894	–	–	–
Processing commitments(5)	4,578	4,689	4,769	4,088	21,464
Gas transportation(6)	4,876	3,590	313	11	–
Capital commitments(7)	42,971	57,843	–	–	–
Total	56,776	547,800	5,429	4,831	22,093

(1) If not extended by May 31, 2022, the SLL Facility will cease to revolve and all outstanding balances will become repayable May 31, 2023.
(2) Relates to the variable operating costs, which are a non-lease component of the Company's head office sublease and sublease expansion. The Tamarack head office sublease and sublease expansion expire on September 30, 2025.
(3) Relates to the scheduled payments on the repayable government loan funding receivable from the government of Canada under the terms of the ERF agreement signed by the Company related to the Nipisi gas conservation program.
(4) Pipeline commitments to deliver a minimum of 636 m^3/d of crude oil/condensate and 455 m^3/d of crude oil subject to a take-or-pay provision of $9.00/$m^3$ and $9.70/$m^3$, respectively, escalating approximately 2% per annum. The terms started on January 1, 2019 and last for 60 months.
(5) Processing commitments to guarantee firm capacity in various facilities.
(6) Gas transportation costs on long term firm contracts which are in various locations at variable rates.
(7) Initial commitment of $200.0 million of capital to further develop the GORR Nipisi/Clearwater and Grande Prairie lands prior to December 31, 2023 of which $100.8 million is remaining to be incurred.

23. 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.

24. Subsequent events:

a) **Declaration of dividend:**

The Company's Board of Directors declared monthly cash dividends of $0.0083 per share on January 13, 2022 and February 14, 2022. On February 15, 2022 the Company paid its inaugural monthly cash dividend to shareholders of record at the close of business on January 31, 2022, The Company's dividend declared on February 14, 2022 is payable on March 15, 2022 to shareholders of record at the close of business on February 28, 2022. These monthly cash dividends are designated as "eligible dividends" for Canadian income tax purposes.

b) **Issuance of senior unsecured sustainability-linked notes:**

On February 10, 2022 the Company issued $200 million aggregate principal amount of 7.25% senior unsecured sustainability-linked notes due May 10, 2027 (the "Notes"). The notes were offered through a private placement underwriting agreement entered into on February 2, 2022. The Notes are issued at par 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. The Notes are being issued in accordance with the Company's Sustainability-Linked Bond Framework which sets out certain sustainability performance targets on the Notes ("NSPTs") including:

- Greenhouse Gas Emissions Intensity: 39% reduction in Scope 1 and 2 emissions by 2025 over the 2020 baseline.
- Indigenous Workforce Participation: target workforce representation of 6% or greater by 2025.

The Company notes that failure to meet the NSPTs will result in an increase in the interest rate payable of 75 basis points for the Greenhouse Gas Emissions Intensity reduction target, and 25 basis points for the Indigenous Workforce Participation target from and including May 10, 2026.

c) **Acquisition of Crestwynd Exploration Ltd.**

On February 15, 2022 the Company acquired all of the issued and outstanding common shares of Crestwynd Exploration Ltd. ("Crestwynd') for total consideration of approximately $222.0 million. The assets acquired from Crestwynd included certain oil and natural gas properties in the Southern Clearwater area. The acquisition was completed for total cash consideration of approximately $92.6 million and the issuance of approximately 26.3 million common shares of the Company at the date of closing share price of $4.92 per common share. Assets acquired in this transaction will be included in the Clearwater oil CGU.

CORPORATE INFORMATION

Directors

John Rooney - Chairman (1)(3)(4)

Jeff Boyce(1)(4)

John Leach(1)(2)

Ian Currie(2)(4)

Rob Spitzer(2)(3)

Marnie Smith(1)(3)

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

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

Stikeman Elliott LLP

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange
Stock symbol: TVE

Management Team

Brian Schmidt
President & Chief Executive Officer

Steve Buytels
VP Finance & Chief Financial Officer

Kevin Screen
Chief Operating Officer

Martin Malek
VP Engineering

Christine Ezinga
VP Corporate Planning & Business Development

Scott Shimek
VP Production & Operations

Scott Reimond
VP Exploration

Sony Gill
Corporate Secretary

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