tamarack valley ENERGY ltd.

MANAGEMENT'S REPORT

The accompanying consolidated financial statements and all information in this report are the responsibility of management. Management, in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of Tamarack Valley Energy Ltd. (the "Company"). The consolidated financial statements have been prepared within acceptable limits of materiality and when necessary, management has made estimates using their best judgment.

Management is responsible for the integrity of the financial information. Management has established internal control systems designed to provide reasonable assurance that transactions are properly authorized, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable accounting information for financial reporting purposes.

The Company's Board of Directors is responsible for ensuring that Management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Company's Audit Committee, with assistance from the Reserves Committee regarding the annual evaluation of our petroleum and natural gas reserves. The Audit Committee meets regularly with Management and their external auditors to discuss internal controls over financial reporting process, audit results and financial reporting matters to satisfy itself that each party is discharging its responsibilities, and to review the consolidated financial statements and the external auditors' report. The external auditors have access to the Audit Committee on a quarterly basis without the presence of management. The Board of Directors has approved the consolidated financial statements.

(signed)	*(signed)*
Brian Schmidt	Ron Hozjan
President & Chief Executive Officer	Vice-President & Chief Financial Officer

Calgary, Alberta
March 6, 2018

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INDEPENDENT AUDITORS' REPORT

To the Shareholders of Tamarack Valley Energy Ltd.

We have audited the accompanying consolidated financial statements of Tamarack Valley Energy Ltd., which comprise the consolidated statements of financial position as at December 31, 2017 and December 31, 2016, the consolidated statements of loss and comprehensive loss, changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements 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 entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Tamarack Valley Energy Ltd. as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants

March 5, 2018

Calgary, Canada

TAMARACK VALLEY ENERGY LTD.

Consolidated Balance Sheets
(thousands)

	December 31, 2017	December 31, 2016
Assets		
Current assets:		
Accounts receivable	$38,673	$16,557
Prepaid expenses and deposits	3,095	1,369
Fair value of financial instruments (note 5)	1,941	–
	43,709	17,926
Property, plant and equipment (note 7)	1,162,272	601,420
Exploration and evaluation assets (note 9)	1,828	2,504
Deferred tax asset (note 14)	–	41,714
	$1,207,809	$663,564
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$51,059	$25,015
Fair value of financial instruments (note 5)	7,936	10,704
	58,995	35,719
Bank debt (note 17)	163,889	45,227
Fair value of financial instruments (note 5)	1,482	–
Decommissioning obligations (note 10)	177,793	112,115
Deferred flow-through share premium	–	765
Deferred tax liability (note 14)	31,795	–
Shareholders' equity:		
Share capital (note 15)	850,357	537,554
Contributed surplus	27,180	21,942
Deficit	(103,682)	(89,758)
	773,855	469,738
Commitments (note 19)		
Subsequent event (note 5)		
	$1,207,809	$663,564

See accompanying notes to the consolidated financial statements.
Approved on behalf of the Board of Directors:

(signed)
Floyd Price
Director

(signed)
Dean Setoguchi
Director

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Loss and Comprehensive Loss
For the years ended December 31, 2017 and 2016
(thousands, except per share amounts)

	2017	2016
Revenue:		
Oil and natural gas	$283,672	$115,517
Royalties	(29,134)	(8,795)
Realized gain on financial instruments (note 5)	5,639	12,296
Unrealized gain (loss) on financial instruments (note 5)	3,495	(23,172)
	263,672	95,846
Expenses:		
Production	82,239	44,067
General and administration	12,462	7,395
Transaction costs (note 6)	5,663	596
Stock-based compensation (note 18)	4,360	3,523
Finance (note 12)	10,834	5,088
Depletion, depreciation and amortization (notes 7 and 9)	148,649	65,427
Loss on disposition of property, plant and equipment (note 7)	–	1,473
Impairment (notes 8 and 9)	17,000	715
	281,207	128,284
Loss before taxes	(17,535)	(32,438)
Deferred income tax recovery (note 14)	3,611	4,615
Net loss and comprehensive loss	$(13,924)	$(27,823)
Net loss per share (note 16):		
Basic and diluted	$(0.06)	$(0.23)

See accompanying notes to the consolidated financial statements.

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Changes in Shareholders' Equity
(thousands)

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2016	99,971	$416,075	$17,044	$(61,935)	$371,184
Issue of common shares	35,104	117,337	–	–	117,337
Issue of flow-through shares	2,452	10,503	–	–	10,503
Share issue costs, net of tax of $1,790.8	–	(4,841)	–	–	(4,841)
Transfer on exercise of stock options	–	104	(104)	–	–
Flow-through share premium	–	(1,624)	–	–	(1,624)
Stock-based compensation	–	–	5,002	–	5,002
Net loss	–	–	–	(27,823)	(27,823)
Balance at December 31, 2016	137,527	$537,554	$21,942	$(89,758)	$469,738
Issue of common shares	90,983	311,698	–	–	311,698
Share issue costs, net of tax of $5.5	–	(14)	–	–	(14)
Transfer on exercise of stock options	–	1,119	(1,119)	–	–
Stock-based compensation	–	–	6,357	–	6,357
Net loss	–	–	–	(13,924)	(13,924)
Balance at December 31, 2017	228,510	$850,357	$27,180	$(103,682)	$773,855

See accompanying notes to the consolidated financial statements.

TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Cash Flows
For the years ended December 31, 2017 and 2016
(thousands)

	2017	2016
Cash provided by (used in):		
Operating:		
Net loss	$(13,924)	$(27,823)
Depletion, depreciation and amortization (notes 7 and 9)	148,649	65,427
Stock-based compensation (note 18)	4,360	3,523
Loss on disposition of property, plant and equipment (note 7)	–	1,473
Accretion expense on decommissioning obligations (note 10)	3,741	1,696
Unrealized loss (gain) on financial instruments (note 5)	(3,495)	23,172
Impairment (notes 8 and 9)	17,000	715
Deferred income tax recovery (note 14)	(3,611)	(4,615)
Abandonment expenditures (note 10)	(898)	(218)
Changes in non-cash working capital (note 13)	(7,297)	(2,612)
Cash provided by operating activities	144,525	60,738
Financing:		
Change in bank debt	118,662	(37,595)
Proceeds from issuance of shares	1,606	127,840
Share issue costs	(19)	(6,633)
Cash provided by financing activities	120,249	83,612
Investing:		
Property, plant and equipment additions (note 7)	(183,210)	(53,834)
Exploration and evaluation additions (note 9)	(9,092)	(2,985)
Acquisitions (note 6)	(116,439)	(85,060)
Proceeds from disposal of property, plant and equipment (note 7)	5,301	2,198
Changes in non-cash working capital (note 13)	38,666	(4,669)
Cash used in investing activities	(264,774)	(144,350)
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: Tamarack Acquisition Corp. and Tamarack Valley Ridge Holdings Ltd. The Company also has a subsidiary incorporated in the United States: Tamarack Ridge Resources Inc. On January 11, 2017, Tamarack Acquisition Corp. and Spur Resources Ltd., completed a vertical amalgamation under the *Business Corporations Act* (Alberta) to form "Tamarack Acquisition Corp.".

Tamarack is a publicly traded company, incorporated and domiciled in Canada. The address of its registered office is Suite 4000, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9. The address of its head office is currently Suite 600, 425 – 1st Street S.W., Calgary, Alberta T2P 3L8.

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 5, 2018.

(b) Basis of measurement:

The consolidated financial statements have been prepared on the historical cost basis except for certain derivative financial instruments 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 in regards to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risk and materiality.

Judgments are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land and other relevant assumptions.

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 reserves have been found in assessing if technical feasibility and commercial viability has been achieved.

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 estimates and their assumptions made by management affecting the measurement of balances and transactions in these consolidated financial statements.

Estimation of recoverable quantities of proven and probable reserves include estimates and assumptions regarding future commodity prices, exchange rates, discount rates and production and transportation costs for future cash flows and the amount and timing of further development capital as well as the interpretation of complex geological and geophysical models and data. Changes in reported reserves can affect the impairment of assets, the decommissioning obligations, the economic feasibility of exploration and evaluation assets and the amounts reported for depletion, depreciation and amortization of property, plant and equipment. These reserve estimates are verified by third party professional engineers, 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.

In a business combination, management makes estimates of the fair value of assets acquired and liabilities assumed which includes assessing the value of oil and gas properties based upon the estimation of recoverable quantities of proven and probable reserves being acquired.

The Company's estimate of stock-based compensation is dependent upon estimates of historic volatility and forfeiture rates.

The Company's estimate of the fair value of derivative financial instruments is dependent on estimated forward prices and volatility in those prices.

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.

The purchase method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. 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, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in profit or loss.

ii) 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 financial statements as is common in the Canadian oil and gas industry.

iii) 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) Non–derivative financial instruments:

Non–derivative financial instruments may be comprised of cash and cash equivalents, accounts receivable, bank debt and accounts payable and accrued liabilities. Non–derivative financial instruments are recognized initially at fair value plus, for instruments not at fair value through profit or loss, any directly attributable transaction costs. Subsequent to initial recognition, non–derivative financial instruments are measured as described below.

Cash and cash equivalents may include cash on hand, term deposits held with banks and other short–term, highly liquid investments with original maturities of three months or less.

The Company's non–derivative financial instruments, such as cash and cash equivalents, accounts receivable, bank debt and accounts payable and accrued liabilities, are measured at amortized cost using the effective interest method, less any impairment losses.

ii) Derivative financial instruments:

The Company has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus not applied hedge accounting, even though the Company considers all commodities contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are recorded on the balance sheet at fair value. Transaction costs are recognized in profit or loss when incurred.

The Company has accounted for its forward physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the balance sheet. Settlements on these physical sales contracts are recognized in profit or loss.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized immediately in profit or loss.

iii) 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.

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

i) Recognition and measurement:

Exploration and evaluation expenditures:

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

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

Exploration and evaluation 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, exploration and evaluation assets are evaluated at a CGU level.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven and/or probable reserves are determined to exist. A review of each exploration license or field is carried out, at least annually, to ascertain whether proven and/or probable reserves have been discovered.

Upon determination of proven and/or probable reserves, exploration and evaluation assets attributable to those reserves are first tested for impairment and then reclassified from exploration and evaluation 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 CGU's 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 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 proven and probable 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. These estimates are reviewed by independent reserve engineers at least annually.

Exploration and evaluation assets pertaining to 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. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that the Company will obtain ownership by the end of the lease term.

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 residual values are reviewed at each reporting date.

(d) Leased assets:

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability.

Other leases are operating leases, which are not recognized on the Company's balance sheet. Payments made under operating leases are recognized in profit or loss on a straight–line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

(e) Impairment:

i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in profit or loss.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

ii) Non–financial assets:

The carrying amounts of the Company's non–financial assets, other than E&E (exploration and evaluation) assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. E&E assets, which are evaluated with the related cash-generating unit 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.

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.

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 proven and probable 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 exploration and evaluation 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 and restricted 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:

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product is transferred to the buyer which is usually when legal title passes to the external party.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

(i) Finance income and expenses:

Finance expense comprises interest expense on bank debt, 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.

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

(j) Income tax:

Income tax expense comprises 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) Flow–through shares:

The resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow–through share arrangements are renounced to investors in accordance with tax legislation. On issuance, the premium received on the flow–through shares, being the difference in price over a common share with no tax attributes, is recognized on the balance sheet. As expenditures are incurred the deferred tax liability associated with the renounced tax deductions are recognized in profit or loss along with a pro–rata portion of the deferred premium.

(l) 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. 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 and restricted share units granted to employees.

(m) Future standards and interpretations:

Leases - In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet, while operating leases are recognized in profit or loss when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expenses upon implementation. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 *Revenue from Contracts with Customers*, has been applied, or is applied at the same date as IFRS 16. The Company is currently evaluating the impact of adopting IFRS 16 on the Company's consolidated financial statements and is in the process of gathering and analyzing contracts that will fall into scope of this standard.

Revenue from contracts with customers - In September 2015, the IASB published an amendment to IFRS 15, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance with a single comprehensive accounting model. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Early adoption is permitted. Based on management's assessment undertaken to date of the effects of applying the new standard, no material changes to net income are expected. The Company expects to include increased qualitative and quantitative disclosures in its financial statements about its contracts with customers, performance obligations and disaggregation of revenue.

Financial Instruments - In July 2014, the IASB issued IFRS 9 *Financial Instruments* to replace IAS 39, which provides a single model for classification and measurement based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial instruments. For financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in other comprehensive income rather than net earnings, unless this creates an accounting mismatch. IFRS 9 includes a new, forward looking 'expected credit loss' impairment model that will result in more timely recognition of expected credit losses. In addition, IFRS 9 provides a substantially-reformed approach to hedge accounting. The standard is effective for annual periods beginning on or after January 1, 2018, with required retrospective application and early adoption permitted. The adoption of IFRS 9 is not expected to have a material impact on the Company's consolidated financial statements.

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 exploration and evaluation 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 market value of oil and natural gas interests (included in property, plant and equipment) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. The market value of other items of property, plant and equipment and exploration and evaluation 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, 2017 and 2016, 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 and restricted 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 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 oil and natural gas volumes 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.

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,	**2017**	2016
Accounts receivable	**$38,673**	$16,557
Fair value of financial instruments	**1,941**	–
Total	**$40,614**	$16,557

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. 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. As such a provision for doubtful accounts has not been recorded at December 31, 2017 and 2016.

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 **2017**	 2016
Oil and natural gas marketing companies	**$33,753**	$14,079
Joint venture partners	**2,968**	1,219
Other	**1,952**	1,259
Total accounts receivable	**$38,673**	$16,557

The Company's seven most significant customers, six Canadian oil and natural gas marketers, and one joint venture partner, account for $34,172 of the accounts receivables at December 31, 2017 (December 31, 2016: five Canadian oil and natural gas marketers, and two joint venture partners accounted for $14,279). The Company had received payment for $33,650 by the end of February, 2018. The Company has the ability to offset approximately 90% of the remaining outstanding amounts against current accounts payable from the same joint venture partners.

As at December 31, 2017 and 2016, the Company's accounts receivable is aged as follows:

(thousands)	**2017**	2016
Current (less than 90 days)	**$37,726**	$15,907
Past due (more than 90 days)	**947**	650
Total accounts receivable	**$38,673**	$16,557

(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 banking line 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 expenditure. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month. In addition, the Company maintains a $290,000 revolving credit facility to provide capital when needed, of which $125,937 was available at the end of 2017.

The timing of cash flows relating to financial liabilities as at December 31, 2017 is as follows:

(thousands)	Total	1 Year	2 to 3 years	Beyond 3 years
Account payable and accrued liabilities	$51,059	$51,059	$–	$–
Bank debt	163,889	–	163,889	–
Total financial liabilities	$214,948	$51,059	$163,889	$–

(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 did not have any foreign exchange contracts as at December 31, 2016; however, due to the significant number of US priced commodity hedges at December 31, 2017, the Company also held hedges to mitigate foreign exchange risk as detailed in the table below.

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 loan fluctuates with the interest rates posted by the lenders. The Company is exposed to interest rate risk and has not entered into any mitigating interest rate hedges or swaps. Had the borrowing rate been 100 basis points higher (or lower) throughout the year ended December 31, 2017, net loss would have been affected by $1,101 (December 31, 2016 – $411) 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 and also world economic events that dictate the levels of supply and demand.

At December 31, 2017, the Company held derivative commodity and foreign exchange contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn $000s)
Crude oil	500 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	Cdn $73.59	$(91)
Crude oil	4,400 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	US $54.26	$(2,554)
Crude oil	4,200 bbls/day	April 1, 2018 – June 30, 2018	WTI fixed price	US $53.74	$(2,427)
Crude oil	3,700 bbls/day	July 1, 2018 – September 30, 2018	WTI fixed price	US $53.94	$(1,663)
Crude oil	2,400 bbls/day	October 1, 2018 – December 31, 2018	WTI fixed price	US $53.79	$(2,448)
Crude oil	500 bbls/day	January 1, 2019 – December 31, 2019	WTI written call option	US $52.00	$(1,482)
Natural gas	25,000 GJ/day	January 1, 2018 – March 31, 2018	AECO fixed price	Cdn $3.16	$2,826
Natural gas	15,000 MMBTU/day	January 1, 2018 – March 31, 2018	AECO/Henry Hub Basis	US $1.34	$(19)
Foreign exchange	1,595,000 US$/mth	January 1, 2018 – March 31, 2018	Exchange rate	Cdn $1.31	$279
Foreign exchange	1,040,000 US$/mth	April 1, 2018 – June 30, 2018	Exchange rate	Cdn $1.29	$102
					$(7,477)

At December 31, 2017, the commodity contracts were fair valued with a liability of $7,477 (December 31, 2016 - $10,704 liability) recorded on the balance sheet and an unrealized gain of $3,495 recorded in earnings for the year ended December 31, 2017 (December 31, 2016 - $23,172 unrealized loss).

Subject Contract	Effect of an increase in price on after-tax earnings	Effect of a decrease in price on after-tax earnings
Cdn $1.00 change in the oil price	$(1,280)	$1,280
Cdn $0.10 change in the gas price	$(265)	$265
Cdn $0.01 change in the exchange rate	$(88)	$88

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, 2017, the Company held no physical commodity contracts.

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, 2017**	December 31, 2016
Risk management contracts		
Current asset	**$1,941**	$–
Current liability	**(7,936)**	(10,704)
Long-term liability	**(1,482)**	–
Balance, end of the year	**$(7,477)**	$(10,704)

Since December 31, 2017, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	600 bbls/day	March 1, 2018 – March 31, 2018	WTI fixed price	Cdn $77.70
Crude oil	1,000 bbls/day	April 1, 2018 – June 30, 2018	WTI fixed price	US $62.76
Crude oil	300 bbls/day	April 1, 2018 – June 30, 2018	WTI fixed price	Cdn $80.17
Foreign exchange	495,000 US$/month	April 1, 2018 – June 30, 2018	Exchange rate	Cdn $1.274
Crude oil	1,500 bbls/day	July 1, 2018 – September 30, 2018	WTI fixed price	US $61.37
Crude oil	2,700 bbls/day	October 1, 2018 – December 31, 2018	WTI fixed price	US $60.18
Crude oil	1,100 bbls/day	January 1, 2019 – March 31, 2019	WTI fixed price	US $59.28

Since December 31, 2017, the Company has entered into the following physical commodity contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,050 bbls/day	March 1, 2018 – April 30, 2018	WTI/Edm Differential	US $5.25
Crude oil	1,500 bbls/day	July 1, 2018 – December 31, 2018	WTI/Edm Differential	US $5.50

(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.

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 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, abandonment expenditures and transaction costs. The Company's strategy during a period of stable commodity prices is to maintain a ratio of not more than 1.5 times. 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.

With the recent decrease in commodity prices and increased volatility in the oil and gas industry, Tamarack's strategy remains focused on preserving its balance sheet by limiting capital spending to projected cash provided by operation activities, using strip prices. The Company's 2017 capital expenditure program was based on exiting 2017 with a debt to adjusted funds flow ratio of less than 1.0 times.

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, 2017, the Company's ratio of net debt to annualized fourth quarter adjusted funds flow was 0.8 to 1.

($ thousand)	**December 31, 2017**	December 31, 2016
Working capital deficiency	**$9,291**	$7,089
Bank debt	**163,889**	45,227
Net debt	**173,180**	52,316
Quarterly adjusted funds flow	**$57,583**	$20,453
Annualized factor	**4**	4
Annualized adjusted funds flow	**230,332**	81,812
Debt to annualized adjusted funds flow	**0.8x**	0.6x

There were no changes in the Company's approach to capital management during the year.

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 oil and natural gas reserves.

6. Corporate and property acquisitions:

(a) Spur Resources Ltd.

On January 11, 2017, Tamarack acquired Spur Resources Ltd. ("Spur") by acquiring all of the issued and outstanding common shares of Spur with the issuance of 90,143 common shares of the Company and $57,809 of cash (the "Viking Acquisition"). The Viking Acquisition builds upon the Company's existing Viking asset base at Redwater and core Cardium assets at Wilson Creek. The operations from the Viking Acquisition have been included in Tamarack's results commencing on January 11, 2017.

Based upon Tamarack's share price on the date of closing being January 11, 2017 of $3.44 per share, the total consideration paid by Tamarack was approximately $367,901.

The Company incurred transaction costs of $5,663 in connection with the Viking Acquisition which were expensed through the statement of loss.

The Viking Acquisition has been accounted for as a business combination. The allocation of the purchase price is as follows:

Consideration (thousands):	
Cash consideration	$57,809
Share consideration (90,142,906 common shares)	310,092
Total consideration	$367,901
Net Assets Acquired (thousands):	
Current assets	$39,684
Current liabilities	(10,517)
Risk management contracts	(269)
Bank debt	(47,115)
Property, plant and equipment	481,685
Decommissioning obligations	(19,207)
Deferred tax liability	(76,360)
Net assets	$367,901

The fair value of property, plant and equipment has been estimated with reference to an independently prepared reserves evaluation for the acquired properties. The fair value of decommissioning obligations was initially estimated using a credit-adjusted risk-free rate of 8%.

Oil and natural gas revenue of $62,271 and a net loss of $1,077 are included in the statement of loss for the Viking Acquisition properties since the closing date of January 11, 2017.

If the acquisition had occurred on January 1, 2017, the incremental oil and natural gas revenue and loss recognized for the year ended December 31, 2017 and the pro forma results would have been as follows:

Year ended December 31, 2017 (thousands)	As stated	Spur Resources Ltd. prior to Acquisition	Pro Forma
Oil and natural gas revenue	$283,672	$2,616	$286,288
Net loss	$(13,924)	$(227)	$(14,151)

(1) This pro forma information is not necessarily indicative of results of operations that would have resulted had the acquisition been effected on the dates indicated.

(b) Penny and Redwater

On July 12, 2016, the Company acquired certain working interests in developed petroleum and natural gas properties in the Penny area of Southern Alberta ("Penny Acquisition") for an aggregate cash purchase price of approximately $58,827 after closing adjustments.

On July 25, 2016, the Company acquired certain working interests in developed petroleum and natural gas properties in the Redwater and Wilson Creek areas of Alberta ("Redwater Acquisition") for an aggregate cash purchase price of approximately $27,330 after closing adjustments.

The Penny Acquisition represented a new oil-weighted core area for the Company focused on the Barons formation, while the Redwater Acquisition complemented the Company's existing Viking oil properties. The operations from the acquisitions have been included in the results of the Company commencing in July of 2016. The Company incurred transaction costs of $596, which were expensed through the statement of loss.

The allocation of the purchase price is as follows:

Consideration (thousands):	**Penny Acquisition**	**Redwater Acquisition**	**Total**
Cash	$58,827	$26,234	$85,061
Working capital settled	–	1,096	1,096
Total consideration	$58,827	$27,330	$86,157
Net Assets Acquired (thousands):			
Prepaid expenses	$948	$897	$1,845
Property, plant and equipment	67,466	37,627	105,093
Decommissioning obligations	(9,587)	(11,194)	(20,781)
Net assets	$58,827	$27,330	$86,157

The fair value of property, plant and equipment has been determined with reference to a reserve report. The fair value of decommissioning obligations was initially estimated using a credit-adjusted risk free rate of 8%.

Included in the statement of loss are the following amounts for the Penny and Redwater Acquisitions since the date of acquisitions:

	Penny Acquisition	Redwater Acquisition	Total
Oil and natural gas revenue	$9,095	$6,331	$15,426
Net income (loss)	$406	$(492)	$(86)

If the Penny and Redwater properties had been acquired on January 1, 2016, the incremental oil and natural gas revenue and income recognized for the year ended December 31, 2016 and the pro forma results would have been as follows:

Year ended December 31, 2016 (thousands)	As stated	Penny Acquisition prior to acquisition	Redwater Acquisition prior to acquisition	Pro Forma
Oil and natural gas revenue	$115,517	$9,603	$6,220	$131,340
Net loss	$(27,823)	$(672)	$(4,597)	$(33,092)

7. Property, plant and equipment:

($ thousands)	Oil and natural gas interests	Other assets	Total
Cost:			
Balance at January 1, 2016	$716,388	$601	$716,989
Property acquisition (note 6)	105,093	–	105,093
Cash additions	53,401	433	53,834
Decommissioning costs	28,622	–	28,622
Stock-based compensation	1,479	–	1,479
Transfer from exploration and evaluation assets (note 9)	1,212	–	1,212
Disposals	(7,025)	–	(7,025)
Balance at December 31, 2016	899,170	1,034	900,204
Corporate acquisition (note 6)(1)	493,200	–	493,200
Cash additions	182,876	334	183,210
Decommissioning costs	43,705	–	43,705
Stock-based compensation	1,997	–	1,997
Transfer from exploration and evaluation assets (note 9)	8,980	–	8,980
Disposals	(5,378)	–	(5,378)
Balance at December 31, 2017	$1,624,550	$1,368	$1,625,918
Depletion, depreciation and impairment losses:			
Balance at January 1, 2016	$235,109	$265	$235,374
Depletion and depreciation	64,494	173	64,667
Disposals	(1,257)	–	(1,257)
Balance at December 31, 2016	298,346	438	298,784
Depletion and depreciation	147,623	239	147,862
Impairment	17,000	–	17,000
Balance at December 31, 2017	$462,969	$677	$463,646

(thousands, except per share and per unit amounts)

	Oil and natural gas interests	Other assets	Total
Carrying amounts:			
At December 31, 2016	$600,824	$596	$601,420
At December 31, 2017	$1,161,581	$691	$1,162,272

(1) Includes $11,515 of minor property acquisitions.

(a) Security:

At December 31, 2017 and 2016, all of the Company's properties are pledged as security for the bank debt (note 17).

(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:

For the year ended December 31, 2017 the Company disposed of its interest in certain oil and gas infrastructure for $5,000 and two non-core, non-producing properties for $301 for total proceeds of $5,301. The Company has entered into operating leases regarding certain oil and gas infrastructure, payments of which is included in commitments (note 19). For the year ended December 31, 2016 the Company disposed of three non-core, producing properties for $2,198.

(d) Other:

The calculation of depletion at December 31, 2017 includes estimated future development costs of $694,759 (December 31, 2016 – $400,816) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $44,825 (December 31, 2016 – $32,759).

8. Impairment:

Impairment of $17,000 was recorded as at December 31, 2017 as a result of a negative technical reserve revision and a decrease in current and forecast future commodity prices. The impairment recognized relates to the Company's heavy oil ($13,000) and shallow gas ($4,000) cash-generating units ("CGUs"). The recoverable amount of these CGU's as at December 31, 2017 was estimated to be $3,664 for the heavy oil CGU and $nil for the shallow gas CGU based on the net present value of before tax cash flows from proved plus probable reserves estimated by the Company at discount rates in excess of 20% (level 3 inputs). The recoverable amount of Tamarack's CGUs was estimated using the fair value less costs of disposal methodology based on what Tamarack could get for these assets if it disposed of them in the current environment taking into account the recent increase to heavy oil differentials and lower natural gas prices. As the recoverable amount of a CGU is sensitive to a decrease in commodity prices, further impairment charges could be recorded in future periods.

As at December 31, 2017, all else being equal, a 1% increase in the assumed discount rate or a 5% decrease in future planned cash-flows would not significantly affect the impairment expense recognized.

The following benchmark reference price estimates were used in determining whether an impairment or reversal to the carrying value of the CGUs existed at December 31, 2017, as forecasted by the independent external reserves evaluator based on an average of those used by three independent industry reservoir engineering companies:

	2018	2019	2020	2021	2022	2023	2024	2025	Thereafter
Exchange rate (US$/Cdn$)(1)	0.7900	0.8000	0.8167	0.8283	0.8400	0.8433	0.8433	0.8433	0.8433
WTI (US$/bbl)(1)	57.50	60.90	64.13	68.33	71.19	73.15	75.16	77.17	+2.0%/yr
Edmonton Par (Cdn$/bbl)(1)	68.60	72.02	74.48	78.60	80.84	82.83	85.17	87.53	+2.0%/yr
AECO (Cdn$/MMbtu)(1)	2.43	2.77	3.19	3.48	3.67	3.76	3.85	3.93	+2.0%/yr

(1) Price forecast, effective January 1, 2018.

9. Exploration and evaluation assets:

($ thousands)	Total
Cost:	
Balance at January 1, 2016	$22,083
Additions	2,985
Transfer to property, plant and equipment (note 7)	(1,212)
Balance at December 31, 2016	23,856
Additions	9,092
Transfer to property, plant and equipment (note 7)	(8,980)
Balance at December 31, 2017	$23,968
Amortization and impairment:	
Balance at January 1, 2016	$19,878
Amortization	760
Impairment	715
Balance at December 31, 2016	21,353
Amortization	787
Balance at December 31, 2017	$22,140

	Total
Carrying amounts:	
At December 31, 2016	$2,504
At December 31, 2017	$1,828

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the period. As at December 31, 2016 the Company recognized an impairment of $715 related to the drill and abandonment of four vertical stratigraphic test wells in the Hatton area (heavy oil CGU).

10. 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 $177,811 at December 31, 2017 (December 31, 2016 – $114,307), which is expected to be incurred between 2018 and 2041. A risk-free rate of 2.3% (December 31, 2016 – 2.3%) and an inflation rate of 2% (December 31, 2016 – 2%) is used to calculate the present value of the decommissioning obligations at December 31, 2017 as presented in the table below:

($ thousands)	**December 31, 2017**	December 31, 2016
Balance, beginning of the year	**$112,115**	$63,331
Liabilities incurred	**12,689**	1,546
Liabilities acquired (note 6)	**19,207**	20,782
Change in estimates	**1,815**	(5,970)
Change in discount rate on acquisition	**29,201**	33,045
Expenditures	**(898)**	(218)
Liabilities disposed	**(77)**	(2,097)
Accretion	**3,741**	1,696
Balance, end of the year	**$177,793**	$112,115

The decommissioning obligations acquired in the Viking Acquisition were initially recognized using a credit-adjusted risk-free discount rate of 8%. It was subsequently revalued using the risk-free rate noted above resulting in the change in discount rate on acquisition in the above table with the offset to property, plant and equipment.

The change in estimates for the years ended December 31, 2017 and 2016 resulted from the decommissioning obligations being revalued at the year-end risk-free rates.

11. Personnel expenses:

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

Years ended December 31, (thousands)	**2017**	2016
Wages and salaries	**$8,867**	$5,460
Benefits and other personnel costs	**1,403**	664
Stock-based compensation	**5,950**	4,488
Total employee remuneration	**16,220**	10,612
Capitalized portion of total remuneration	**(5,342)**	(3,555)
	$10,878	$7,057

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 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 VP Engineering, the VP Land, the VP Exploration and the VP Production and Operations. Executive officers, employees and directors may also participate in the Company's option and restricted share unit program. Key executive officers' and directors compensation is comprised of the following:

Years ended December 31, (thousands)	**2017**	2016
Salaries, wages and short-term benefits	**$3,339**	$2,596
Share-based payments (1)	**3,204**	2,946
	$6,543	$5,542

(1) Represents the amortization of stock-based compensation associated with restricted share units and options granted to executive officers and directors as recorded in the financial statements.

12. Finance expenses:

Years ended December 31, (thousands)	**2017**	2016
Interest on bank debt	**$7,093**	$3,392
Accretion of decommissioning obligations	**3,741**	1,696
	$10,834	$5,088

13. Supplemental cash flow information:

Changes in non-cash working capital consists of:

Years ended December 31, (thousands)	**2017**	2016
Source/(use) of cash:		
Accounts receivable	**$(22,116)**	$(985)
Prepaid expenses and deposits	**(1,726)**	(330)
Accounts payable and accrued liabilities	**26,044**	(6,715)
Working capital acquired (note 6)	**29,167**	749
	$31,369	$(7,281)
Related to operating activities	**$(7,297)**	$(2,612)
Related to investing activities	**$38,666**	$(4,669)

14. Income taxes:

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

Years ended December 31, (thousands)	**2017**	2016
Loss before taxes	**$(17,535)**	$(32,438)
Expected tax rate	**26.95%**	27.0%
Expected income tax recovery	**(4,726)**	(8,758)
Flow-through shares	**(90)**	1,302
Change in unrecognized deferred tax assets	**(502)**	977
Stock-based compensation	**1,175**	951
Change in rates and other	**532**	913
Deferred income tax recovery	**$(3,611)**	$(4,615)

In 2017, the blended statutory tax rate was 26.95% (December 31, 2016 – 27.0%).

Deferred tax assets and liabilities are attributable to the following:

Years ended December 31, (thousands)	**2017**	2016
Deferred tax liabilities:		
Property, plant and equipment	**$(134,411)**	$(44,528)
Deferred tax assets:		
Financial instruments	**2,020**	2,890
Non-capital losses	**50,580**	49,401
Share issue costs	**2,469**	3,680
Decommissioning obligations	**47,547**	30,271
Total	**$(31,795)**	$41,714

In calculating the deferred income tax liability in 2017, the Company included $190,000 (December 31, 2016 - $186,000) of non-capital losses available for carry forward to reduce taxable income in future years. These losses expire between 2026 and 2036.

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

Years ended December 31, (thousands)	**2017**	2016
Property, plant and equipment	**$16,829**	$18,687

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

(thousands)	Balance January 1, 2016	Recognized in equity	Recognized in profit or loss	Other	Balance December 31, 2016
Property, plant and equipment	$(20,547)	$ –	$(18,077)	$(859)	$(39,483)
Non-capital losses	43,686	–	5,715	–	49,401
Decommissioning obligations	17,099	–	13,172	–	30,271
Share issue costs	3,364	1,791	(1,475)	–	3,680
Unrecognized deferred tax assets	(4,069)	–	(976)	–	(5,045)
Financial instruments	(3,366)	–	6,256	–	2,890
Total	$36,167	$1,791	$4,615	($859)	$41,714

(thousands)	Balance January 1, 2017	Recognized in equity	Recognized in business combinations	Recognized in profit or loss	Other	Balance December 31, 2017
Property, plant and equipment	$(39,483)	$ –	$(94,763)	$5,143	$(765)	$(129,868)
Non-capital losses	49,401	–	11,200	(10,021)	–	50,580
Decommissioning obligations	30,271	–	7,103	10,173	–	47,547
Share issue costs	3,680	5	–	(1,216)	–	2,469
Unrecognized deferred tax assets	(5,045)	–	–	502	–	(4,543)
Financial instruments	2,890	–	100	(970)	–	2,020
Total	$41,714	$5	$(76,360)	$3,611	$(765)	$(31,795)

15. Share capital:

At December 31, 2017 and 2016 the Company was authorized to issue an unlimited number of common shares and preferred shares without nominal or par value.

2017:

On January 11, 2017, the Company issued 90,143 common shares in connection with the Viking Acquisition (note 6).

During the year ended December 31, 2017, 812 stock options at $1.98 per share were exercised for gross proceeds of $1,606. There were also 28 restricted share awards converted to common shares.

2016:

On December 29, 2016, the Company issued 500 flow-through common shares, related to Canadian exploration expenditures, at $5.00 per share for total gross proceeds of $2,500. Under the terms of the flow-through share agreements, the Company is required to renounce the $2,500 of qualifying oil and natural gas expenditures effective December 31, 2016 and must incur the expenditures by December 31, 2017. As of December 31, 2017, the Company has incurred the full $2,500 of qualifying expenditures.

On July 12, 2016, the Company completed a bought deal financing by issuing 20,110 common shares at $3.66 per share for total gross proceeds of $73,603. This included an over-allotment option that was exercised for 2,623 common shares. Certain officers, directors and employees acquired 100 common shares for gross proceeds of $366.

On July 12, 2016, the Company also issued 1,952 flow-through common shares, related to Canadian development expenditures, at $4.10 per share for total gross proceeds of $8,003. The Company renounced these expenditures on December 31, 2016 and had fully incurred the required expenditures.

On March 18, 2016, the Company completed a bought deal financing by issuing 14,966 common shares at $2.92 per share for total gross proceeds of $43,701. This included an over-allotment option that was exercised for 1,952 common shares. Certain officers, directors and employees acquired 281 common shares for gross proceeds of $821.

During the year ended December 31, 2016, 16 stock options at $2.06 per share were exercised for gross proceeds of $33. There were also 12 restricted share awards converted to common shares.

16. Loss per share:

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

Years ended December 31, (thousands, except per share amounts)	**2017**	2016
Net loss	**$(13,924)**	$(27,823)
Weighted average shares - basic and diluted	**225,306**	122,235
Net loss per share-basic and diluted	**$(0.06)**	$(0.23)

Per share amounts have been calculated using the weighted average number of shares outstanding. For the year ended December 31, 2017, 11,484 stock options, preferred shares and restricted stock units were excluded from the diluted earnings per share as they were anti-dilutive. For the year ended December 31, 2016, 9,501 stock options, preferred shares and restricted stock units were excluded from the diluted earnings per share as they were anti-dilutive.

17. Bank debt:

The Company currently has available a revolving credit facility in the amount of $270,000 and a $20,000 operating facility (collectively the “Facility”) with a syndicate of lenders. The Facility, totaling $290,000, lasts for a 364-day period and will be subject to its next 364-day extension by May 25, 2018.

If not extended on May 25, 2018, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 25, 2019.

The interest rate on the Facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio as defined in the Facility. The interest rate will vary depending on the lending vehicle employed and the Company's 12-month trailing debt-to-cash-flow ratio. Interest on banker's acceptance ("BA") notes will vary from a low of the bank's posted BA rate plus 2.0% to a high of the bank's posted BA rate plus 3.5% while interest on prime lending varies from a low of the bank's prime rate plus 1.0% to a high of the bank's prime rate plus 2.5%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.5% to a high of 0.875% on the undrawn portion of the Facility. The Facility has been secured by a $550,000 supplemental debenture with a floating charge over all assets. As the available lending limits of the Facility are based on the bank's 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. The next review is scheduled for May 2018.

At December 31, 2017, the Company had utilized the Facility in the amount of $163,889. The interest rate applicable to the drawn amounts as of this date was 4.45%. As at December 31, 2017, the Company had letter of guarantees outstanding in the amount of $174 against the Facility.

There are no financial covenants governing the Facility. Non-financial covenants include reporting requirements, permitted indebtedness, permitted hedging and other standard business operating covenants. As at December 31, 2017, the Company is in compliance with all covenants.

18. Share-based payments:

(a) Preferred share plan:

There are 1,155 preferred shares of Tamarack Acquisition Corp. outstanding which are exchangeable into 1,111 common shares of the Company (December 31, 2016 – 1,111). The preferred shares are fully vested at December 31, 2017 and are exchangeable into common shares of the Company at an exchange price of $3.12 per common share.

Under the terms of the Company's preferred share plan, a cashless settlement alternative is available, whereby preferred share-holders can either (i) elect to receive shares by delivering cash to the Company in the amount of the preferred shares, or (ii) elect to receive a number of shares equivalent to the market value of the preferred share over the exercise price. For the years ended December 31, 2017 and 2016 there were no preferred shares exercised.

(b) Stock option plan:

Under the Company's stock option and restricted share unit plan it may grant up to 22,851 options or restricted share units to its employees, directors and consultants of which 10,374 options and restricted stock units have been issued that apply against this maximum amount. Stock options are granted at the market price of the shares at the date of grant, have a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were 140 options granted during the year ended December 31, 2017 (December 31, 2016 – 945).

The fair value of each option granted during the year 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:

	2017	2016
Risk free rate (%)	**1.02**	0.92
Expected volatility (%)	**80**	80
Expected life (years)	**5**	5
Forfeiture rate (%)	**–**	–
Dividend ($ per share)	**–**	–
Fair value at grant date ($ per option)	**2.00**	2.14

The number and weighted average exercise prices of stock option plan are as follows:

	Number of options (thousands)	Weighted average exercise price
Outstanding, January 1, 2016	4,669	$ 3.59
Granted	945	3.44
Exercised	(16)	2.06
Expired	(271)	4.55
Outstanding, December 31, 2016	5,327	$ 3.52
Granted	140	3.01
Exercised	(812)	1.98
Expired	(99)	2.79
Outstanding, December 31, 2017	**4,556**	**$ 3.79**

The following table summarizes information about stock options outstanding and exercisable at December 31, 2017:

	Options outstanding			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
$ 1.86 – 3.00	916	$2.68	2.6	602	$2.65
$ 3.01 – 5.00	3,174	$3.66	1.9	2,411	$3.70
$ 5.01 – 6.82	466	$6.82	1.6	466	$6.82
$ 1.86 – 6.82	**4,556**	**$3.79**	**2.0**	**3,479**	**$3.93**

(c) Restricted stock unit plan:

The Company has a restricted stock unit plan that allows the Board of Directors to grant restricted share awards to directors, officers and employees. Subject to terms and conditions of the restricted stock unit plan, each restricted share award 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. The weighted average fair value of awards granted for the year ended December 31, 2017 was $2.81 (December 31, 2016 - $3.44). There were 2,785 restricted stock units granted during the year ended December 31, 2017 (December 31, 2016 – 1,214).

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 award value in cash or in common shares of the Company.

The following table summarizes information about the restricted share awards:

	Number of awards (thousands)
Outstanding, January 1, 2016	1,861
Granted	1,214
Exercised	(12)
Outstanding, December 31, 2016	3,063
Granted	2,785
Exercised	(28)
Forfeited	(2)
Outstanding, December 31, 2017	**5,818**
Exercisable, December 31, 2017	**1,743**

19. Commitments:

The following table summarizes the Company's commitments as at December 31, 2017:

($ thousands)	2018	2019	2020	2021	2022	2023	2024+
Office lease	542	542	263	–	–	–	
Take or pay commitments(1)	986	–	–	–	–	–	
Rental fee(2)	5,741	5,741	5,741	5,741	3,870	1,999	1,142
Gas transportation(3)	2,448	730	229	76	–	–	
Total	9,717	7,013	6,233	5,817	3,870	1,999	1,142

(1) Pipeline commitment to deliver a minimum of 300 m3/d of crude oil/condensate subject to a take-or-pay provision of $9.00/m3. The remaining term is 12 months.

(2) Rental fee of $0.3 million per month for a maximum period of 90 months starting in January 2015 relating to four facilities, rental fee of $0.1 million per month for a maximum period of 96 months starting in January 2016 relating to four facilities and rental fee of $0.05 million per month for a maximum period of 96 months starting in January 2018 relating to one facility.

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

CORPORATE INFORMATION

Directors

Floyd Price - Chairman(3)

Dean Setoguchi(1)

David MacKenzie(1)(2)

Jeff Boyce(1)(2)

Noralee Bradley(3)(4)

John Leach(1)(3)

Ian Currie(2)(4)

Rob Spitzer(3)(4)

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 Health, Safety & Environmental Committee of the Board of Directors

Management Team

Brian Schmidt
President & Chief Executive Officer

Ron Hozjan
VP Finance & Chief Financial Officer

Dave Christensen
VP Engineering

Ken Cruikshank
VP Land

Kevin Screen
VP Production & Operations

Scott Reimond
VP Exploration

Sony Gill
Corporate Secretary

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

McCarthy Tétrault

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange
Stock symbol: TVE

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