MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the three months ended March 31, 2018 and 2017. This MD&A is dated and based on information available on May 9, 2018 and should be read in conjunction with the unaudited condensed consolidated interim financial statements and notes for the three months ended March 31, 2018 and 2017. Additional information relating to Tamarack, including Tamarack's Annual Information Form, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

The condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standard ("IAS") 34 "Interim Financial Reporting". The Company uses certain non-IFRS measures in this MD&A. For a discussion of those measures, including the method of calculation, please refer to the section titled "Non-IFRS Measures" beginning on page 17. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

Q1 2018 Financial and Operating Highlights

- Achieved record corporate production in Q1/18 of 23,532 boe/d, up 3% over Q4/17 volumes of 22,807 boe/d and up 32% over Q1/17 volumes of 17,796 boe/d.
- Oil and natural gas liquids ("NGL") weighting was 63% in Q1/18 compared to 57% in the same period of 2017, an increase of 11%, which positively contributed to the Company's stronger netbacks year-over-year.
- Total adjusted operating field netbacks (previously referred to as "adjusted funds flow"; see "Non-IFRS Measures") increased 81% to $58.5 million in Q1/18 ($0.26 per share basic and $0.25 per share diluted), from $32.4 million in Q1/17 ($0.15 per share basic and diluted).
- Operating netbacks of $30.11/boe in Q1/18 increased by 31% over Q1/17 primarily due to the 11% increase in oil and NGL weighting, and the 18% increase in the combined average realized prices for oil and NGL.
- Net production and transportation expenses in Q1/18 were 6% lower at $10.76/boe compared to $11.42/boe in Q1/17.
- Invested $69.6 million on drilling, completing and equipping nine (9.0 net) Cardium oil wells, 29 (28.0 net) Viking oil wells and five (4.7 net) Redwater oil wells. The Company also completed and brought on production 15 (14.4 net) Viking oil wells that were drilled in late Q4/17 and drilled eight (8.0 net) Viking oil wells that will be brought on production in the second quarter of 2018.

Production

Quarter-over-Quarter

	Q1 2018	Q4 2017	% change
Production			
Light oil (bbls/d)	**13,239**	12,189	9
Heavy oil (bbls/d)	**299**	500	(40)
Natural gas liquids (bbls/d)	**1,347**	1,459	(8)
Natural gas (mcf/d)	**51,879**	51,956	–
Total (boe/d)	**23,532**	22,807	3
Percentage of oil and natural gas liquids	**63%**	62%	2

Average production for the first quarter of 2018 increased 3% over the previous quarter and reflects the positive impact of first quarter drilling. Contributing to this increase was an additional 698 boe/d from Wilson Creek/Alder Flats (59% oil and NGL) and 1,364 boe/d from the Veteran development program (86% oil and NGL). These gains were partially offset by expected declines from legacy volumes.

The Company's oil and NGL weighting increased by 2% in the first quarter of 2018 compared to the fourth quarter of 2017, attributable to the higher oil-weighted drilling program in the Veteran and Wilson Creek areas of Alberta. For the remainder of 2018, the Company expects its oil and NGL weighting to increase further and range between 64% – 67%. The weighting will ultimately depend on the timing of production additions from the higher oil-weighted areas of Wilson Creek, Penny and Veteran, relative to additions from the higher natural gas-weighted area of Alder Flats.

Year-over-Year

	Three months ended March 31,		
	2018	2017	% change
Production			
Light oil (bbls/d)	**13,239**	7,891	68
Heavy oil (bbls/d)	**299**	484	(38)
Natural gas liquids (bbls/d)	**1,347**	1,779	(24)
Natural gas (mcf/d)	**51,879**	45,852	13
Total (boe/d)	**23,532**	17,796	32
Percentage of oil and natural gas liquids	**63%**	57%	11

Compared to the prior year, average first quarter 2018 production increased by 32%. This increase is attributable to the successful Wilson Creek and Veteran development drilling program through 2017 and the first quarter of 2018, partially offset by expected production declines from legacy assets.

Petroleum and Natural Gas Sales

Quarter-over-Quarter

	Q1 2018	Q4 2017	% change
Revenue ($ thousands)			
Oil and NGL	**$88,226**	$81,139	9
Natural gas	**10,510**	9,021	17
Total	**$98,736**	$90,160	10
Average realized price			
Light oil ($/bbl)	**67.92**	65.08	4
Heavy oil ($/bbl)	**45.23**	48.97	(8)
Natural gas liquids ($/bbl)	**45.14**	44.03	3
Combined average oil and NGL ($/boe)	**65.86**	62.34	6
Natural gas ($/mcf)	**2.25**	1.89	19
Revenue ($/boe)	**46.62**	42.97	8
Benchmark pricing:			
West Texas Intermediate (US$/bbl)	**62.91**	55.39	14
Edmonton Par (Cdn$/bbl)	**72.30**	66.86	8
Hardisty Heavy (Cdn$/bbl)	**46.90**	48.69	(4)
AECO daily index (Cdn$/mcf)	**2.07**	1.68	23
AECO monthly index (Cdn$/mcf)	**1.84**	1.95	(6)

Revenue from oil, natural gas and NGL sales was 10% higher in the first quarter of 2018 compared to the fourth quarter of 2017. Stronger revenue quarter-over-quarter is attributable to the increase in production volumes, a higher oil weighting and increased pricing for crude oil, NGL and natural gas.

WTI crude oil markets remained strong during the first quarter of 2018 and in the month of April showed continued growth, reaching two-year highs that surpassed US$68.00/bbl. The average first quarter WTI price of US$62.91/bbl was 14% higher than the average fourth quarter price of US$55.39/bbl. With significant improvements in the WTI markets, Tamarack's realized light oil price for the three months ended March 31, 2018 increased 4% to $67.92/bbl from $65.08/bbl in the previous quarter. Through the first quarter, the WTI to Edmonton Par differential experienced significant widening and volatility associated with a shortage of pipeline take-away capacity. The result was an average US$5.85/bbl differential for the first quarter of 2018 versus the US$1.15/bbl in the fourth quarter of 2017. This increased differential combined with a stronger Canadian dollar through the middle of the quarter significantly eroded the value of the Edmonton Par Canadian price per barrel relative to WTI. Should the market continue to experience apportionment with take-away capacity limitations, the differential is likely to remain wide and volatile, which will continue to reduce the value of the Edmonton Par price relative to WTI in future quarters.

NGL prices remained stable with a slight increase of 3% in the first quarter to $45.14/bbl from $44.03/bbl in the fourth quarter of 2017. The increase in WTI across the quarter led to an increase in butane and condensate prices, as the contracts are priced relative to WTI. However, decreasing propane prices across the quarter offset most of these gains, resulting in a modest overall increase to NGL pricing. New contracts for the 2018-19 contract season have been negotiated and were in effect for April 1, 2018.

Tamarack's realized natural gas price increased 19% to $2.25/mcf in the first quarter of 2018 compared to $1.89/mcf in the previous quarter. This was slightly less than the AECO daily benchmark price increase of 23% however, still a premium to the AECO daily index for the first quarter of 2018, reflecting Tamarack's efforts to reduce exposure to the local Alberta gas market.

The Company's gas market exposure is reflected below:

Gas Market	Percentage Exposure (as at March 31, 2018)	Percentage Exposure (as at April 1, 2018)[1]
AECO Daily (5A)	11.9	40.3
AECO Daily (5A) + premium (SK)	24.9	19.3
Dawn	4.7	8.1
Chicago	4.7	8.1
Michigan City Gate	4.7	8.1
Malin	4.7	16.1
Financial Fixed Price (Hedged)	44.4	0.0
	100%	100%

[1] Based on forecast 2018 production volumes. Exposure between AECO Daily (5A) and AECO Monthly (7A) may change from time to time.

While prices remained strong throughout the first quarter due to winter weather-related demand and a prolonged winter season, continued oversupply in the province combined with restrictions on take-away capacity are expected to create volatility and depress prices in the AECO daily index beginning in the second quarter of 2018. During the fourth quarter of 2017, Tamarack entered into an additional gas sales contract with a third party, commencing April 1, 2018, which will further diversify the Company's natural gas price exposure. With the addition of this contract, approximately 40% of Tamarack's total natural gas production will be diversified to alternate US markets, including Malin, Chicago, Michigan Consolidated and Dawn daily index pricing less transportation tolls, until 2022. Tamarack will continue to explore alternatives to minimize exposure to Alberta gas market fluctuations.

Year-over-Year			
	Three months ended March 31,		
	2018	2017	% change
Revenue ($ thousands)			
Oil and NGL	**$88,226**	$50,942	73
Natural gas	**10,510**	11,928	(12)
Total	**$98,736**	$62,870	57
Average realized price			
Light oil ($/bbl)	**67.92**	63.02	8
Heavy oil ($/bbl)	**45.23**	44.64	1
Natural gas liquids ($/bbl)	**45.14**	26.46	71
Combined average oil and NGL ($/boe)	**65.86**	55.74	18
Natural gas ($/mcf)	**2.25**	2.89	(22)
Revenue ($/boe)	**46.62**	39.25	19
Benchmark pricing:			
West Texas Intermediate (US$/bbl)	**62.91**	51.71	22
Edmonton Par (Cdn$/bbl)	**72.30**	64.69	12
Hardisty Heavy (Cdn$/bbl)	**46.90**	50.49	(7)
AECO daily index (Cdn$/mcf)	**2.07**	2.69	(23)
AECO monthly index (Cdn$/mcf)	**1.84**	2.93	(37)

Revenue from oil, natural gas and NGL sales for the three months ended March 31, 2018 increased by 57% relative to the same period in 2017 primarily due to increases in production and oil and NGL prices, partially offset by a decrease in realized natural gas prices.

The Company may use both financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates. All such transactions are conducted within risk management tolerances that are reviewed quarterly by Tamarack's Board of Directors. At March 31, 2018, the Company held derivative commodity and foreign exchange contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	300 bbls/day	April 1, 2018 – June 30, 2018	WTI fixed price	Cdn $80.17
Crude oil	5,200 bbls/day	April 1, 2018 – June 30, 2018	WTI fixed price	US $55.49
Crude oil	5,200 bbls/day	July 1, 2018 – September 30, 2018	WTI fixed price	US $56.08
Crude oil	5,100 bbls/day	October 1, 2018 – December 31, 2018	WTI fixed price	US $57.17
Crude oil	1,500 bbls/day	January 1, 2019 – March 31, 2019	WTI fixed price	US $59.65
Crude oil	500 bbls/day	January 1, 2019 – December 31, 2019	WTI call option	US $52.00
Foreign exchange	2,515,000 US$/month	April 1, 2018 – June 30, 2018	Exchange rate	Cdn $1.2836
Foreign exchange	4,335,000 US$/month	July 1, 2018 – September 30, 2018	Exchange rate	Cdn $1.2819
Foreign exchange	1,370,000 US$/month	October 1, 2018 – December 31, 2018	Exchange rate	Cdn $1.2844

At March 31, 2018, the commodity contracts were fair valued with a liability of $15.0 million (December 31, 2017 - $7.5 million liability) recorded on the balance sheet and an unrealized loss of $7.5 million recorded in earnings for the three months ended March 31, 2018 (December 31, 2017 - $3.5 million unrealized gain).

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

At March 31, 2018, the Company held the following physical commodity contracts.

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,050 bbls/day	April 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
Natural gas	10,000 GJ/day	April 1, 2018 – April 30, 2018	AECO fixed price	Cdn $1.47

Since March 31, 2018, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	300	October 1, 2018 – December 31, 2018	WTI fixed price	US $62.05
Crude oil	900	January 1, 2019 – March 31, 2019	WTI fixed price	US $62.64
Crude oil	300	April 1, 2019 – June 30, 2019	WTI fixed price	US $61.65

Royalties

Quarter-over-Quarter

	Q1 2018	Q4 2017	% change
Royalty expenses ($ thousands)	**$10,938**	$8,464	29
$/boe	**5.16**	4.03	28
percent of sales	**11**	9	22

Royalties as a percentage of revenue were higher in the first quarter of 2018 compared to the fourth quarter of 2017 due to prior period gas cost allowance adjustments that were recorded in the fourth quarter of 2017.

Year-over-Year

	Three months ended March 31,		
	2018	2017	% change
Royalty expenses ($ thousands)	**$10,938**	$6,641	65
$/boe	**5.16**	4.15	24
percent of sales	**11**	11	–

Royalties as a percentage of revenue were comparable in the first quarter of 2018 compared to the first quarter of 2017. The Company expects royalty rates as a percentage of revenue to remain in the 10% – 12% range for the remainder of 2018 based on current commodity pricing.

Net Production and Transportation Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q1 2018**	Q4 2017	% change
Production and transportation expenses	**$23,114**	$22,189	4
Less: processing income	**336**	371	(9)
Total net production and transportation expenses	**$22,778**	$21,818	4
Total ($/boe)	**$10.76**	$10.40	3

Net production and transportation expenses per boe for the first quarter of 2018 increased 3% compared to the fourth quarter of 2017, attributable to the severity and length of the current season's winter months. On an absolute basis, overall costs increased in the first quarter of 2018 over the fourth quarter of 2017 due to higher production and a slight increase in per unit costs. For 2018, the Company expects operating costs to average between $10.60/boe and $10.80/boe.

Year-over-Year

	Three months ended March 31,		
($ thousands, except per boe)	**2018**	2017	% change
Production and transportation expenses	**$23,114**	$18,635	24
Less: processing income	**336**	344	(2)
Total net production and transportation expenses	**$22,778**	$18,291	25
Total ($/boe)	**$10.76**	$11.42	(6)

For the three months ended March 31, 2018, net production and transportation expenses per boe were lower compared to the same period in 2017 as a result of increased production volumes from the Veteran area, where operating costs are lower than the corporate average. In addition, higher volumes across fixed costs results in lower per boe costs. On an absolute basis, net production and transportation expenses increased due to higher production volumes generated over the period.

Tamarack entered into a commitment agreement on a take-or-pay basis to deliver at least 4,000 bbls of oil per day to a midstream company's new 120 km pipeline (the "Viking Pipeline Project"). The Viking Pipeline Project will extend the reach of the existing Provost pipeline and support Tamarack's planned development of the Veteran Viking oil play by ensuring the Company has access to oil markets, with initial capacity of 13,300 bbls/d and the potential to expand up to 25,000 bbls/d. This contract will eliminate the need for Tamarack to truck oil sales to markets and is anticipated to reduce Veteran operating costs by approximately $1.45/boe contributing to corporate production and transportation cost savings of approximately $0.40 to $0.50/boe in 2019. The midstream company has indicated the Viking Pipeline Project is expected to be operational by the end of the first quarter of 2019.

Operating Netback

Quarter-over-Quarter

($/boe)	**Q1 2018**	Q4 2017	% change
Average realized sales	**$46.62**	$42.97	8
Royalty expenses	**(5.16)**	(4.03)	28
Net production and transportation expenses	**(10.76)**	(10.40)	3
	30.70	28.54	8
Realized commodity hedging gain (loss)	**(0.59)**	1.53	(139)
Operating netback	**$30.11**	$30.07	-

The Company's operating netback for the first quarter of 2018 was comparable to the fourth quarter of 2017.

Year-over-Year

	Three months ended March 31,		
($/boe)	**2018**	2017	% change
Average realized sales	**$46.62**	$39.25	19
Royalty expenses	**(5.16)**	(4.15)	24
Net production and transportation expenses	**(10.76)**	(11.42)	(6)
	30.70	23.68	30
Realized commodity hedging loss	**(0.59)**	(0.77)	(23)
Operating netback	**$30.11**	$22.91	31

For the three months ended March 31, 2018, operating netbacks increased 31% over the same period in 2017, supported by the Company's higher oil and NGL weighting (63% vs. 57%), improved realized prices for crude oil and NGL, and a 6% decrease in net production and transportation expenses per boe. These gains were offset by a higher royalty expense per boe and lower realized natural gas prices.

General and Administrative ("G&A") Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q1 2018**	Q4 2017	% change
Gross costs	**$4,224**	$4,257	(1)
Capitalized costs and recoveries	**(845)**	(842)	-
General and administrative costs	**$3,379**	$3,415	(1)
Total ($/boe)	**$1.60**	$1.63	(2)

Gross G&A expenses and net G&A costs per boe remained consistent between the first quarter of 2018 and the fourth quarter of 2017.

Year-over-Year

	Three months ended March 31,		
($ thousands, except per boe)	**2018**	2017	% change
Gross costs	**$4,224**	$3,712	14
Capitalized costs and recoveries	**(845)**	(780)	8
General and administrative costs	**$3,379**	$2,932	15
Total ($/boe)	**$1.60**	$1.83	(13)

Gross G&A costs increased in the three months ended March 31, 2018, compared to the same period in 2017, due to staffing increases arising from the Spur Viking acquisition (the "Viking Acquisition"). Net G&A costs per boe in the three months ended March 31, 2018 were lower than the same period in 2017 due to scale efficiencies associated with the 32% increase in production.

Stock-Based Compensation Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q1 2018**	Q4 2017	% change
Gross cost	**$2,038**	$1,618	26
Capitalized costs	**(524)**	(481)	9
Total stock-based compensation	**$1,514**	$1,137	33
Total ($/boe)	**$0.71**	$0.54	31

Stock-based compensation expenses related to stock options ("options") and restricted share unit awards ("RSUs") were higher in the first quarter of 2018 compared to the fourth quarter of 2017, due to RSUs being granted at the end of the fourth quarter of 2017. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

Year-over-Year

	Three months ended March 31,		
($ thousands, except per boe)	**2018**	2017	% change
Gross cost	**$2,038**	$1,583	29
Capitalized costs	**(524)**	(513)	2
Total stock-based compensation	**$1,514**	$1,070	41
Total ($/boe)	**$0.71**	$0.67	6

Stock-based compensation expenses related to options and RSUs were higher for the three months ended March 31, 2018, due to increased staffing levels to manage Tamarack's 32% production growth in 2017, which resulted in more RSUs being granted at the end of the fourth quarter of 2017. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

For the three months ended March 31, 2018, the Company issued 0.2 million options at a weighted average exercise price of $2.62 per share. Additionally, 0.2 million options at $2.41 per share were exercised for total gross proceeds of $0.4 million, while 0.1 million RSUs were settled.

Interest Expense

Quarter-over-Quarter

($ thousands, except per boe)	**Q1 2018**	Q4 2017	% change
Interest on bank debt	**$1,841**	$2,097	(12)
Total ($/boe)	**$0.87**	$1.00	(13)
Average drawings on bank debt	**$164,671**	$175,373	(6)

Interest expense was lower in the first quarter of 2018 compared to the fourth quarter of 2017, due to a lower average amount drawn quarter-over-quarter on the revolving credit facility and the benefits of utilizing a larger amount of banker's acceptance notes which had lower rates than the bank's prime rate.

Year-over-Year

	Three months ended March 31,		
($ thousands, except per boe)	**2018**	2017	% change
Interest on bank debt	**$1,841**	$1,420	30
Total ($/boe)	**$0.87**	$0.89	(2)
Average drawings on bank debt	**$164,671**	$128,164	28

Interest expense for the three months ended March 31, 2018 was higher than the same period in 2017. This is attributable to an interest rate increase that occurred during the third quarter of 2017 and to a higher average amount drawn in the first quarter of 2018 on the revolving credit facility related to increased capital spending.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

The Company depletes its property, plant and equipment ("PP&E") based on its proved plus probable reserves. The carrying value of undeveloped land in exploration and evaluation assets is also amortized over its term to expiry, which is charged to DDA&A expense.

Quarter-over-Quarter

($ thousands, except per boe)	**Q1 2018**	Q4 2017	% change
Depletion and depreciation	**$43,284**	$41,569	4
Amortization of undeveloped leases	**174**	197	(12)
Accretion	**1,007**	1,035	(3)
Total	**$44,465**	$42,801	4
Depletion and depreciation ($/boe)	**$20.44**	$19.81	3
Amortization ($/boe)	**0.08**	0.09	(11)
Accretion ($/boe)	**0.48**	0.49	(2)
Total ($/boe)	**$21.00**	$20.39	3

For the first quarter of 2018, DDA&A expense per boe increased 3% compared to the fourth quarter of 2017. The increase was due to higher facility and infrastructure capital allocated to the Veteran area in Q1/18 to complete the second phase battery expansion, which will accommodate the Company's expected production growth through 2018. On an absolute basis, DDA&A expense was higher quarter-over-quarter due to increased production volumes.

Year-over-Year

($ thousands, except per boe)	Three months ended March 31, 2018	2017	% change
Depletion and depreciation	**$43,284**	$31,860	36
Amortization of undeveloped leases	**174**	197	(12)
Accretion	**1,007**	906	11
Total	**$44,465**	$32,963	35
Depletion and depreciation ($/boe)	**$20.44**	$19.89	3
Amortization ($/boe)	**0.08**	0.12	(33)
Accretion ($/boe)	**0.48**	0.57	(16)
Total ($/boe)	**$21.00**	$20.58	2

For the three months ended March 31, 2018, DDA&A expense per boe was higher relative to the same period in 2017. The increase was due to higher facility and infrastructure capital spent in the Veteran area to complete the first and second phase battery expansions during the second half of 2017 and in Q1/18, respectively. On an absolute basis, DDA&A expense was higher for the three months ended March 31, 2018 due to an increase in production volumes.

Income Taxes

The Company did not incur any cash tax expense in the three months ended March 31, 2018, nor does it expect to pay any cash tax in 2018 or 2019 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three months ended March 31, 2018, deferred income tax expense of $1.8 million was recognized compared to a deferred income tax expense of $1.3 million for the same period in 2017.

Adjusted Operating Field Netback and Net Income (Loss)

Quarter-over-Quarter

($ thousands, except per share)	Q1 2018	Q4 2017	% change
Income (loss) before taxes	**$5,073**	$(16,851)	(130)
Depletion, depreciation and amortization	**43,458**	41,766	4
Stock-based compensation	**1,514**	1,137	33
Gain on disposition of property, plant and equipment	**(6)**	–	–
Accretion expense on decommissioning obligations	**1,007**	1,035	(3)
Unrealized loss on financial instruments	**7,499**	13,496	(44)
Impairment of property, plant and equipment	**–**	17,000	(100)
Adjusted operating field netback	**$58,545**	$57,583	2
Per share - basic	**$0.26**	$0.25	4
Per share - diluted	**$0.25**	$0.25	–
Net income (loss)	**$3,294**	$(12,525)	126
Per share - basic	**$0.01**	$(0.05)	120
Per share - diluted	**$0.01**	$(0.05)	120

The adjusted operating field netback (previously referred to as “adjusted funds flow”; see “Non-IFRS Measures”) during the first quarter of 2018 was slightly higher than the fourth quarter of 2017 primarily due to a 3% increase in production volumes.

The Company recorded net income of $3.3 million ($0.01 per share basic and diluted) during the three months ended March 31, 2018, compared to a net loss of $12.5 million ($0.05 per share basic and diluted) for the previous quarter. The factors contributing to net income in the first quarter of 2018 compared to a net loss in the fourth quarter of 2017 included higher oil and natural gas revenue, a lower unrealized hedging loss and the impairment to property, plant and equipment that was recognized during the fourth quarter of 2017. These factors were partially offset by higher royalty expenses.

Year-over-Year

	Three months ended March 31,		
($ thousands, except per share)	**2018**	2017	% change
Income before taxes	**$5,073**	$3,595	41
Depletion, depreciation and amortization	**43,458**	32,057	36
Stock-based compensation	**1,514**	1,070	41
Gain on disposition of property, plant and equipment	**(6)**	–	–
Transaction costs	**–**	5,663	(100)
Accretion expense on decommissioning obligations	**1,007**	906	11
Unrealized loss (gain) on financial instruments	**7,499**	(10,935)	(169)
Adjusted operating field netback	**$58,545**	$32,356	81
Per share - basic	**$0.26**	$0.15	73
Per share - diluted	**$0.25**	$0.15	67
Net income	**$3,294**	$2,290	44
Per share - basic	**$0.01**	$0.01	–
Per share - diluted	**$0.01**	$0.01	–

First quarter 2018 adjusted operating field netback (see “Non-IFRS Measures”) was higher on an absolute basis than the same period in 2017, primarily due to an increase in production and crude oil prices and a 31% increase in operating netbacks. The increase in netbacks was related primarily to the increase in oil and NGL weighting and the reduction in net production and transportation expenses per boe.

The Company recorded net income of $3.3 million ($0.01 per share basic and diluted) during the three months ended March 31, 2018 compared to net income of $2.3 million ($0.01 per share basic and diluted) for the same period in 2017.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

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

($ thousand)	Three months ended March 31, 2018	2017	% change
Land	**$787**	$376	109
Geological and geophysical	**2**	9	(78)
Drilling and completion	**53,186**	47,872	11
Equipment and facilities	**14,899**	14,582	2
Capitalized G&A	**690**	661	4
Office equipment	**66**	221	(70)
Total capital expenditures	**$69,630**	$63,721	9

In the first quarter of 2018, Tamarack successfully executed its planned Q1/18 drilling program and completed the fifteen Viking wells drilled in late Q4/17. Tamarack has invested a total of $69.6 million ($72.4 million including acquisitions, net of dispositions) as of March 31, 2018. During the first quarter of 2018, the Company drilled, completed and equipped nine (9.0 net) Cardium oil wells, 29 (28.0 net) Viking oil wells and five (4.7 net) Redwater oil wells. The Company also completed and brought on production fifteen (14.4 net) Viking oil wells that were drilled in late Q4/17 and drilled eight (8.0 net) Viking oil wells that will be brought on production in the second quarter of 2018.

To complement the Company's drilling and completion projects in Q1/18, Tamarack allocated capital to supplementary projects to manage increased production at facilities controlled by the Company and to further reduce operating costs. These projects included the second phase of the Veteran oil battery expansion to increase emulsion processing capacity as well as the initial costs to reactivate the Veteran gas plant which is expected to be complete in late Q2/18.

As previously disclosed, the Company expects to spend approximately 50% of its $195-205 million capital budget during the first half of 2018.

March 31, 2018 Drilling Summary	Gross	Net
Viking	37.0	36.0
Cardium	9.0	9.0
Other	5.0	4.7
	52.0	50.7

The Company's net undeveloped land totaled 369,559 acres as at March 31, 2018.

Property Acquisitions

During the first quarter of 2018, Tamarack completed one tuck-in acquisition totalling $2.5 million in the Wilson Creek area of Alberta. Through this acquisition, the Company added 18 boe/d and 3.3 (2.1 net) sections of undeveloped land.

Liquidity and Capital Resources

($ thousand)	**March 31, 2018**	March 31, 2017	December 31, 2017
Working capital deficiency	**$20,982**	$30,077	$9,291
Bank debt	**165,750**	135,484	163,889
Net debt	**186,732**	165,561	173,180
Quarterly adjusted operating field netback	**$58,545**	$32,356	$57,583
Annualized factor	**4**	4	4
Annualized adjusted operating field netback	**234,180**	129,424	230,332
Net debt to annualized adjusted operating field netback	**0.8x**	1.3x	0.8x

Tamarack's net debt (see "Non-IFRS Measures"), including working capital deficiency but excluding the fair value of financial instruments, totaled $186.7 million as at March 31, 2018. This compares to the previous quarter and the first quarter of 2017, in which net debt of $173.2 million and $165.6 million was recorded, respectively. Tamarack's first quarter 2018 net debt to annualized adjusted operating field netback ratio remained at 0.8 times.

The $72.4 million invested during the first quarter of 2018 for capital expenditures and property acquisitions, net of dispositions, was funded approximately 81% by Tamarack's adjusted operating field netback ($58.5 million) and approximately 19% ($13.6 million) by an increase in net debt and the minor amount received as a result of stock option proceeds.

With continued commodity price volatility impacting the oil and gas industry, Tamarack's strategy remains focused on preserving balance sheet strength by adjusting capital spending as appropriate to respond to changes in commodity prices. Tamarack intends to maintain balance sheet flexibility which allows the Company to be opportunistic and take advantage of potential opportunities within core areas. Although Tamarack's business remains solid, at times management believes the Company's prevailing share price does not adequately reflect the underlying value of its assets. As such, Tamarack implemented a normal course issuer bid ("NCIB") through the facilities of the Toronto Stock Exchange and alternate trading platforms, pursuant to which Tamarack would have the option to repurchase its common shares for cancellation. The NCIB represents an additional tool that can be employed as part of management's ongoing strategy to increase long-term shareholder value. As of May 9, 2018, the Company spent $836,827 to purchase and cancel 243,500 outstanding common shares under the NCIB.

Further, the Company remains committed to executing its proven strategy of focusing on drilling wells that target a return on capital cost payout of 1.5 years or less, and will continue to control or reduce capital, production and transportation costs where possible. "Capital cost payout" or "payout" are non-IFRS measures and are achieved when revenues, less royalties, production and transportation costs are equal to the total capital costs associated with drilling, completing, equipping and tying-in a well (see "Non-IFRS Measures").

Share Capital

At March 31, 2018, Tamarack had 228,764,381 common shares, 4,595,000 options and 5,800,049 RSUs outstanding. At May 9, 2018, there were 228,520,881 common shares, 4,595,000 options and 5,800,049 RSUs outstanding. This compares to December 31, 2017, at which time there were 228,510,381 common shares, 4,555,667 options and 5,818,382 RSUs outstanding. No preferred shares of Tamarack are issued and outstanding.

At March 31, 2018, and December 31, 2017, there were 1,155,007 preferred shares of Tamarack Acquisition Corp. ("TAC Preferred Shares") which are exchangeable into 1,110,584 common shares of the Company. The TAC Preferred Shares are fully vested at March 31, 2018 and are exchangeable into common shares of Tamarack at an exchange price of $3.12 per common share.

Bank Debt

The Company currently has available a revolving credit facility in the amount of $270 million and a $20 million operating facility (collectively the "Facility") with a syndicate of lenders. The Facility totals $290 million, 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.

The total interest rate on the Facility is determined through a pricing grids 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 current net debt-to-cash-flow ratio. Interest on banker's acceptance ("BA") notes will vary based on a BA pricing grid 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%. Interest on prime lending varies based on a prime rate pricing grid 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 lending vehicles Tamarack employs from time to time will vary based on capital needs and current market rates. The Facility has been secured by a $550 million 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.

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 March 31, 2018, the Company is in compliance with all covenants.

Guidance

Tamarack's Q1/18 production of 23,532 boe/d was slightly above the upper end of its first half range of 22,750 to 23,250 boe/d with a slightly lower oil and NGL weighting of 63% relative to the expected first half weighting of 64-66%.

In response to the currently low natural gas price environment the Company has shut-in 400 boe/d of natural gas production in the second quarter of 2018. As Tamarack is currently ahead of production guidance, the Company anticipates the shut-in gas will not affect the original 2018 production forecast.

The Company successfully executed its first half drilling program all within the first quarter and accelerated the drilling of eight additional Viking net oil wells that are expected to be completed during the second quarter. Approximately 50% of Tamarack's $195-205 million capital budget is expected to be spent during the first half of 2018.

The Company's key 2018 guidance is summarized in the following table:

	2018 Guidance
Average annual production (boe/d)	22,500 - 23,500
Liquids weighting (%)	~64 - 66
Exit production (boe/d)	24,000 - 24,500
Liquids weighting (%)	~65 - 67
Annual capital expenditure range ($millions)	$195 to $205
Year end 2018 net debt(1) to Q4 annualized adjusted operating field netback(2) ratio *(including hedges)*	<1.0 times
Liquidity on existing credit facilities ($millions)	~$100
2018 price assumptions:	
WTI ($US/bbl)	$56.75
Edmonton Par ($CDN/bbl)	$64.60
AECO ($CDN/GJ)	$1.65
Canadian/US dollar exchange rate	$0.79

(1) Refer to definition of net debt under "Non-IFRS Measures"

(2) Refer to definition of adjusted operating field netback under "Non-IFRS Measures"

The Company will continue to closely monitor current and future commodity prices. Should commodity prices significantly fluctuate from levels outlined in the assumptions above, Tamarack will accelerate or reduce capital expenditures, redirect capital to purchase shares through the NCIB program or pay down debt.

Commitments

The following table summarizes the Company's commitments as at March 31, 2018:

($ thousands)	2018	2019	2020	2021	2022	2023	2024+
Bank debt	–	165,750	–	–	–	–	–
Office lease	407	542	263	–	–	–	–
Take or pay commitments(1)	657	2,205	2,256	2,294	2,340	2,396	–
Rental fee(2)	4,306	5,741	5,741	5,741	3,870	1,999	1,142
Gas transportation(3)	1,836	730	229	76	–	–	–
Total	7,206	174,968	8,489	8,111	6,210	4,395	1,142

(3) Pipeline commitment in 2018 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 9 months. Viking Pipeline Project commitment commencing in 2019 to deliver a minimum of 636 m3/d of crude oil/condensate subject to a take-or-pay provision of $9.00/m3. The term starts on January 1, 2019 and lasts for 60 months.

(4) 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.

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

Unit Cost Calculation

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

Abbreviations

AECO	Natural gas storage facility located at Suffield, AB
bbl	barrel
bbl/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
GJ	gigajoule
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
Mmbtu	one million British thermal units
NGL	natural gas liquids
WTI	West Texas Intermediate
CGU	Cash-generating unit

Non–IFRS Measures

This document contains the terms "adjusted operating field netback", "operating netback", "net debt", "netbacks" and "capital cost payout" and "net debt to annualized adjusted operating field netback ratio", which are non-IFRS financial measures. The Company uses these measures to help evaluate its performance. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers. The Company uses adjusted operating field netback as key measures to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. The Company uses net debt (bank debt plus working capital deficiency and excluding the fair value of financial instruments) as an alternative measure of outstanding debt. The Company considers operating netbacks a key measure as it demonstrates corporate profitability relative to current commodity prices. Netbacks, which have no IFRS equivalent, are calculated on a per boe basis by deducting royalties and net production and transportation costs from petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts. The Company also considers capital cost payout a key measure as it demonstrates the financial status of the Company's projects. Net debt to annualized adjusted operating field netback ratio is calculated as net debt divided by the annualized adjusted operating field netback for the most recently completed quarter.

(a) **Adjusted Operating Field Netback -** Tamarack's method of calculating adjusted operating field netback may differ from other companies, and therefore may not be comparable to measures used by other companies. Adjusted operating field netback is calculated by taking net income or loss before taxes and adding back items including: transaction costs; and deducting non-cash items including: stock-based compensation; accretion expense on decommissioning obligations; depletion, depreciation and amortization; and impairment; unrealized gain or loss on financial instruments; and gain or loss on dispositions. Tamarack uses adjusted operating field netback as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment.

(b) **Operating Netback** - Management uses certain industry benchmarks, such as operating netback, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts, less royalties and net production and transportation costs calculated on a per boe basis. Management considers operating netback an important measure to evaluate its operational performance, as it demonstrates field level profitability relative to current commodity prices. The calculation of the Company's netbacks can be seen on page 8 in the section titled "Operating Netback".

(c) **Net Debt -** Tamarack closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. Net debt does not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Management considers net debt an important measure to assist in providing a more complete understanding of cash liabilities.

The following outlines the Company's calculation of net debt (excluding the effect of derivative contracts):

($ thousand)	March 31, 2018	December 31, 2017
Accounts payable and accrued liabilities	$64,256	$51,059
Accounts receivable	(39,892)	(38,673)
Prepaid expenses and deposits	(3,382)	(3,095)
Working capital deficiency	20,982	9,291
Bank debt	165,750	163,889
Net debt	$186,732	$173,180

(d) **Capital Cost Payout** - Management uses certain industry benchmarks, such as capital cost payout, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Capital cost payout is achieved when revenues, less royalties, production and transportation costs are equal to the total capital costs associated with drilling, completing, equipping and tying in a well. Management considers capital cost payout an important measure to evaluate its operational performance, as it demonstrates the economic status of the Company's projects, and allows the Company to understand how quickly capital can be returned from drilling a well, which helps assess the Company's ability to generate value.

Selected Quarterly Information

Three months ended	**Mar. 31, 2018**	Dec. 31, 2017	Sep. 30, 2017	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016
Sales volumes								
Natural gas *(mcf/d)*	**51,879**	51,956	49,987	47,696	45,852	31,226	29,007	27,462
Oil and NGL *(bbls/d)*	**14,885**	14,148	12,210	11,387	10,154	6,249	5,955	4,959
Average boe/d *(6:1)*	**23,532**	22,807	20,541	19,336	17,796	11,453	10,790	9,536
Product prices								
Natural gas *($/mcf)*	**2.25**	1.89	1.62	3.01	2.89	3.27	2.54	1.62
Oil and NGL *($/bbl)*	**65.86**	62.34	50.29	51.77	55.74	52.88	45.29	45.35
Oil equivalent *($/boe)*	**46.62**	42.97	33.83	37.91	39.25	37.76	31.82	28.25
(000s, except per share amounts)								
Financial results								
Oil and natural gas revenues	**98,736**	90,160	63,927	66,715	62,870	39,793	31,588	24,517
Cash provided by operating activities	**60,285**	50,056	35,237	34,537	24,695	17,609	14,086	14,560
Adjusted operating field netback[(1)]	**58,545**	57,583	34,774	33,670	32,356	20,453	17,172	15,364
Per share – basic	**0.26**	0.25	0.15	0.15	0.15	0.15	0.13	0.13
Per share – diluted	**0.25**	0.25	0.15	0.15	0.15	0.15	0.13	0.13
Net income (loss)	**3,294**	(12,525)	(6,742)	3,053	2,290	(8,425)	(3,196)	(10,368)
Per share – basic	**0.01**	(0.05)	(0.03)	0.01	0.01	(0.06)	(0.02)	(0.09)
Per share – diluted	**0.01**	(0.05)	(0.03)	0.01	0.01	(0.06)	(0.02)	(0.09)
Capital expenditures	**69,630**	35,516	74,063	19,002	63,721	14,863	14,497	10,309
Net acquisitions (dispositions)	**2,790**	1,713	2,962	1,301	75,995	(2,446)	85,308	–
Total assets	**1,240,335**	1,207,809	1,206,886	1,178,404	1,186,285	663,564	679,259	542,917
Net debt[(1)]	**186,732**	173,180	194,917	152,354	165,561	52,316	62,817	57,791
Bank debt	**165,750**	163,889	162,164	140,795	135,484	45,227	48,598	48,630
Decommissioning obligations	**182,216**	177,793	167,102	171,909	164,012	112,115	122,810	68,149

(1) Refer to definition of adjusted operating field netback and net debt under “Non-IFRS Measures”

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

- The volatility in commodity prices and the resultant effect on revenue, cash provided by operating activities and earnings.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices which can cause significant fluctuations in earnings due to unrealized gains and losses recognized on a quarterly basis.
- On January 11, 2017, Tamarack closed acquisition of assets in Southeast Alberta and Southwest Saskatchewan (the “Viking Acquisition”); in 2017 this acquisition added $62.3 million to oil and natural gas revenue and contributed $1.1 million to net loss.
- On July 12, 2016 and July 25, 2016, Tamarack closed the Penny and Redwater Acquisitions, respectively; in 2016 these acquisitions added $15.4 million to oil and natural gas revenue and contributed $0.1 million to net loss.
- The Company recorded $5.7 million in transaction costs in the first quarter of 2017 related to the Viking Acquisition and $0.5 million in transaction costs in the third quarter of 2016 related to the Penny and Redwater Acquisitions.

- The Company recorded impairment charges on its heavy oil and certain natural gas related cash-generating units ("CGUs") due to falling oil and gas prices in the amount of $17.0 million in Q4 2017.

Critical Accounting Estimates

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

(a) **Oil and natural gas reserves** – Proved reserves, as defined by the Canadian Securities Administrators in NI 51-101 with reference to the Canadian Oil and Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

An independent reserve evaluator using all available geological and reservoir data, as well as historical production data, has prepared the Company's oil and natural gas reserve estimates. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Company's development plans.

(b) **Exploration and evaluation assets –** The costs of drilling exploratory wells are initially capitalized as exploration and evaluation ("E&E") assets pending the evaluation of commercial reserves. Commercial reserves are defined as the existence of proved and probable reserves which are determined to be technically feasible and commercially viable to extract. Reserves may be considered commercially producible if management has the intention of developing and producing them based on factors such as project economics, quantities of reserves, expected production techniques, estimated production costs and capital expenditures.

(c) **Carrying value of property, plant and equipment ("PP&E")** – PP&E is measured at cost less accumulated depletion, depreciation, amortization and impairment losses. The net carrying value of PP&E and estimated future development costs is depleted using the unit-of-production method based on estimated proved and probable reserves. Changes in estimated proved and probable reserves or future development costs have a direct impact on the calculation of depletion expense.

The Company is required to use judgment when designating the nature of oil and gas activities as E&E assets or development and production assets within PP&E. E&E assets and development and production assets are aggregated into CGUs based on their ability to generate largely independent cash flows. The allocation of the Company's assets into CGUs requires significant judgment with respect to use of shared infrastructure, existence of active markets for the Company's products and the way in which management monitors operations.

E&E expenditures relating to activities to explore and evaluate oil and natural gas properties are initially capitalized and include costs associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and testing, directly attributable overhead and administration expenses, and costs associated with retiring the assets. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined, which is considered to be when proved and/or probable reserves are determined to exist. E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, aggregated at the segment level. The determination of the recoverable amount of a CGU requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and production costs. Changes in any of these assumptions, such as a downward revision in reserves, decrease in commodity prices or increase in costs, could impact the fair value.

The Company assesses PP&E for impairment whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. If any such indication of impairment exists, the Company performs an impairment test related to the specific CGU. The determination of the recoverable amount of a CGU requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and production costs. Changes in any of these assumptions, such as a downward revision in reserves, a decrease in commodity prices or an increase in costs could impact the fair value.

(d) **Decommissioning obligations –** The decommissioning obligations are estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a risk-free rate. The costs are included in PP&E and amortized over the useful life of the asset. The liability is adjusted each reporting period to reflect the passage of time, with the accretion expense charged to net earnings, and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements could be material.

(e) **Stock-based compensation –** The Company uses the fair value method for valuing stock option grants. Under this method, compensation cost attributable to all stock options granted is measured at fair value at the grant date and expensed over the vesting period. The Black-Scholes option pricing model is used to estimate the fair value of the stock options and it contains such estimates as expected share price volatility and the Company's risk-free interest rate. Any changes in these assumptions could alter the fair value and earnings.

(f) **Income taxes** – The determination of income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

(g) **Financial instruments** – The Company utilizes financial instruments to manage the exposure to market risks relating to commodity prices. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices and foreign currency exchange rates.

(h) **Business combinations –** Management's judgment is required to determine whether a transaction constitutes a business combination or asset acquisition as determined based on the criteria in IFRS 3, "Business Combinations". Business combinations are differentiated from an asset acquisition when business processes are associated with the assets.

Business combinations within the scope of IFRS 3 are accounted for using the acquisition method. The acquired identifiable net assets are measured at their fair value at the date of acquisition. Deferred taxes are recognized for any differences between the fair value and the tax basis of net assets acquired. Any excess of the purchase price over the fair value of the net assets acquired is recognized as goodwill.

Future Accounting Pronouncements

The Company has reviewed new and revised accounting pronouncements listed below that have been issued but are not yet effective. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material effect on the reported earnings or net assets of the Company.

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 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 the scope of this standard.

Changes in Accounting Policies

Adoption of IFRS 15, "Revenues from Contracts with Customers"

IFRS 15, "Revenue from Contracts with Customers" ("IFRS 15") was issued by the IASB in May of 2014 and replaces IAS 18 "Revenue", IAS 11 "Construction Contracts", and related interpretations effective for reporting periods beginning on or after January 1, 2018. The new standard provides a single, principles-based five-step analysis of transactions to determine the nature of an entity's obligation to perform and whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized.

The Company has adopted IFRS 15 effective January 1, 2018. Tamarack applied IFRS 15 to all of its contracts with customers using the cumulative effect method. Under this method, prior period financial statements have not been restated. Management reviewed the Company's revenue streams and major contracts with customers using the IFRS 15 principles-based five-step model and concluded there were no material changes to earnings or in the timing of when production revenue is recognized.

Adoption of IFRS 9, "Financial Instruments"

On January 1, 2018, the Company adopted all of the requirements of IFRS 9, "Financial Instruments" ("IFRS 9") which replaces IAS 39, "Financial Instruments: Recognition and Measurement" ("IAS 39"). The retrospective adoption of IFRS 9 had no material impact to the Company's financial statements.

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost; fair value through other comprehensive income ("FVOCI"); or fair value through profit or loss ("FVTPL"). The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics. IFRS 9 eliminates the previous IAS 39 categories of held to maturity, loans and receivables and available for sale. IFRS 9 largely retains the existing requirements in IAS 39 for the classification of financial liabilities.

IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected credit loss" model. The application of the new expected credit loss model did not have a significant impact on the Company's financial assets.

Cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities and bank debt continue to be measured at amortized cost and are now classified as “amortized cost”. There were no changes to Tamarack’s classification of its financial instrument derivative assets and liabilities as FVTPL.

The Company currently has no intentions of designating any of its financial instruments as hedges, nor does the Company currently apply hedge accounting.

Disclosure Controls and Internal Controls over Financial Reporting

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

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

No material changes in the Company’s DCP and its ICFR were identified during the period ended March 31, 2018 that have materially affected, or are reasonably likely to materially affect, the Company’s internal controls over financial reporting.

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

Business Risks

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

Financial Risks

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

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

Operational Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Tamarack depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, existing reserves and their subsequent production will decline over time as they are exploited. A future increase in Tamarack's reserves will depend not only on its ability to explore and develop any properties it may have, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by Tamarack.

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

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

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

Regulatory Risks

Regulatory risks include the possibility of changes to royalty, tax, environmental and safety legislation. Tamarack endeavours to anticipate the costs related to compliance and budget sensibly for them. Changes to environmental and safety legislation may also cause delays to Tamarack's drilling plans, its production efficiencies and may adversely affect its future earnings. Restrictive new legislation is a risk the Company cannot control.

Forward-Looking Statements

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

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

- the intentions of management and the Company;
- the availability, terms, use and renewal of the Facility;

- estimated production rates in 2018;
- future net production and transportation costs and G&A expenses;
- Tamarack's focus on preserving balance sheet strength by adjusting capital spending relative to commodity prices and reducing production costs on newly acquired assets;
- Tamarack's primary focus areas for production growth;
- the Viking Pipeline Project;
- tuck-in acquisitions in Tamarack's core areas;
- future drilling plans;
- the capital cost payout of wells and Tamarack's strategy of focusing on drilling wells that target a certain return on capital cost payout and Tamarack's ability to control cost or reduce capital, production and transportation costs;
- the Veteran oil battery expansion and the reactivation of the Veteran gas plant;
- deferred tax liabilities;
- expectations as to royalty rates as a percentage of revenue;
- future capital expenditures and capital program funding;
- estimated year end net debt to annualized adjusted operating field netback ratio;
- the Company's capital budget program and guidance for 2018;
- the NCIB;
- derivative contracts and physical commodity contracts;
- Tamarack's commodity price, foreign exchange rate and interest rate risk management activities, including the Company's ability to diversify natural gas price exposure;
- expectations for oil, NGL and natural gas pricing in 2018 and beyond; and
- expectations for oil, NGL and natural gas weighting in 2018.

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

- future commodity prices and the actual prices received for the Company's products;
- expected net production and transportation costs and G&A expenses;
- estimated reserves of oil and natural gas;
- the ability to obtain equipment and services in the field in a timely and efficient manner;
- the ability to add production and reserves through acquisition and/or drilling at competitive prices;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the realization of anticipated benefits of acquisitions, including the Penny and Redwater Acquisitions, the Viking Acquisition and the tuck-in acquisition at Penny, and drilling programs in relation thereto;
- drilling results, including field production rates and decline rates;
- the continued application of horizontal drilling and fracturing techniques and pad drilling;
- the continued availability of capital and skilled personnel;
- the ability to obtain financing on acceptable terms;

- the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation;
- the impact of increasing competition;
- the ability of the Company to secure adequate product transportation;
- the ability to enter into future commodity derivative contracts on acceptable terms; and
- the continuation of the current tax, royalty and regulatory regime.

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

- the material uncertainties and risks described under the headings "Critical Accounting Estimates", "Future Accounting Pronouncements", "Disclosure Controls and Internal Controls Over Financial Reporting", "Business Risks", "Financial Risks", "Operational Risks" and "Regulatory Risks";
- the material assumptions and observations described under the headings "Production", "Petroleum and Natural Gas Sales", "Royalties", "Net Production and Transportation Expenses", "Operating Netback", "General and Administrative ("G&A") Expenses", "Stock-Based Compensation Expenses", "Interest Expense", "Depletion, Depreciation, Amortization and Accretion ("DDA&A")", "Income Taxes", "Adjusted Operating Field Netback and Net Income (Loss)", "Capital Expenditures (Including Exploration and Evaluation Expenditures)", "Property Acquisitions", "Liquidity and Capital Resources", "Guidance", "Commitments" and "Selected Quarterly Information";
- the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- delays or changes in plans with respect to exploration or development projects or capital expenditures;
- volatility in market prices for oil and natural gas;
- uncertainties associated with estimating oil and natural gas reserves and the ability of the Company to realize value from its properties;
- geological, technical, drilling and processing problems;
- facility and pipeline capacity constraints and access to processing facilities and to market for production;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- marketing and transportation;
- prevailing weather and break-up conditions;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- net production and transportation costs and future development costs;
- the ability to access sufficient capital from internal and external sources; and
- changes in tax, royalty and environmental legislation.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. The risk factors above should be considered in the context of current economic conditions, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also to be considered are increased levels of political uncertainty and possible changes to existing international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company's business. Additional information on these and other factors that could affect the business, operations or financial results of Tamarack are included in reports on file with applicable securities regulatory authorities, including but not limited to Tamarack's Annual Information Form for the year ended December 31, 2017, which may be accessed on Tamarack's SEDAR profile at www.sedar.com or on the Company's website at www.tamarackvalley.ca.

This MD&A contains future-oriented financial information and financial outlook information (collectively, "FOFI") about Tamarack's prospective results of operations, capital expenditures, debt, net debt, cash flow, adjusted operating field netback, net debt to annualized adjusted operating field netback ratio, production and transportation expenses and components thereof, all of which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs and the assumptions outlined under "Non-IFRS Measures".

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

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets
(unaudited)(thousands)

	March 31, 2018	December 31, 2017
Assets		
Current assets:		
Accounts receivable	$39,892	$38,673
Prepaid expenses and deposits	3,382	3,095
Fair value of financial instruments (note 4)	–	1,941
	43,274	43,709
Property, plant and equipment (note 6)	1,196,078	1,162,272
Exploration and evaluation assets (note 7)	983	1,828
	$1,240,335	$1,207,809
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$64,256	$51,059
Fair value of financial instruments (note 4)	13,470	7,936
	77,726	58,995
Bank debt (note 12)	165,750	163,889
Fair value of financial instruments (note 4)	1,506	1,482
Decommissioning obligations (note 8)	182,216	177,793
Deferred tax liability	33,574	31,795
Shareholders' equity:		
Share capital (note 10)	851,408	850,357
Contributed surplus	28,543	27,180
Deficit	(100,388)	(103,682)
	779,563	773,855
Commitments (note 14)		
Subsequent event (note 4, 6 and 15)		
	$1,240,335	$1,207,809

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Income and Comprehensive Income
For the three months ended March 31, 2018 and 2017
(unaudited)(thousands, except per share amounts)

	2018	2017
Revenue:		
Oil and natural gas (note 5)	$98,736	$62,870
Processing income (note 5)	336	344
Royalties	(10,938)	(6,641)
Realized loss on financial instruments (note 4)	(1,255)	(1,230)
Unrealized gain (loss) on financial instruments (note 4)	(7,499)	10,935
	79,380	66,278
Expenses:		
Production	23,114	18,635
General and administration	3,379	2,932
Transaction costs	–	5,663
Stock-based compensation (note 13)	1,514	1,070
Finance	2,848	2,326
Depletion, depreciation and amortization (note 6 and 7)	43,458	32,057
Gain on disposition of property, plant and equipment	(6)	–
	74,307	62,683
Income before taxes	5,073	3,595
Deferred income tax expense	(1,779)	(1,305)
Net income and comprehensive income	$3,294	$2,290
Net income per share (note 11):		
Basic	$ 0.01	$ 0.01
Diluted	$ 0.01	$ 0.01

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

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

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2018	228,510	$850,357	$27,180	$(103,682)	$773,855
Issue of common shares	254	376	–	–	376
Transfer on exercise of stock options and restricted share awards	–	675	(675)	–	–
Stock-based compensation	–	–	2,038	–	2,038
Net income	–	–	–	3,294	3,294
Balance at March 31, 2018	228,764	$851,408	$28,543	$(100,388)	$779,563

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2017	137,527	$537,554	$21,942	$(89,758)	$469,738
Issue of common shares	90,143	310,092	–	–	310,092
Share issue costs, net of tax of $5.5	–	(15)	–	–	(15)
Stock-based compensation	–	–	1,583	–	1,583
Net income	–	–	–	2,290	2,290
Balance at March 31, 2017	227,670	$847,631	$23,525	$(87,468)	$783,688

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three months ended March 31, 2018 and 2017
(unaudited)(thousands)

	2018	2017
Cash provided by (used in):		
Operating:		
Net income	$3,294	$2,290
Depletion, depreciation and amortization (note 6 and 7)	43,458	32,057
Stock-based compensation (note 13)	1,514	1,070
Gain on disposition of property, plant and equipment	(6)	–
Accretion expense on decommissioning obligations (note 8)	1,007	906
Unrealized loss (gain) on financial instruments (note 4)	7,499	(10,935)
Deferred income tax expense	1,779	1,305
Abandonment expenditures (note 8)	(53)	(201)
Changes in non-cash working capital (note 9)	1,793	(1,797)
Cash provided by operating activities	60,285	24,695
Financing:		
Change in bank debt (note 12)	1,861	90,257
Proceeds from issuance of shares (note 10)	376	–
Share issue costs	–	(21)
Cash provided by financing activities	2,237	90,236
Investing:		
Property, plant and equipment additions (note 6)	(69,407)	(60,116)
Exploration and evaluation additions (note 7)	(223)	(3,605)
Acquisitions	(2,790)	(105,162)
Changes in non-cash working capital (note 9)	9,898	53,952
Cash used in investing activities	(62,522)	(114,931)
Change in cash and cash equivalents	–	–
Cash and cash equivalents, beginning of period	–	–
Cash and cash equivalents, end of period	$ –	$ –

See accompanying notes to the condensed consolidated interim financial statements.

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 condensed consolidated interim 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. No assets are held within Tamarack Ridge Resources Inc. or Tamarack Valley Ridge Holdings Ltd. 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 condensed consolidated interim financial statements have been prepared in accordance with International Accounting Standards 34, "Interim Financial Reporting" of International Financial Reporting Standards ("IFRS").

These condensed consolidated interim financial statements have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company for the year ended December 31, 2017 except as detailed in note 3. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These condensed consolidated interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company's annual filings for the year ended December 31, 2017.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on May 9, 2018.

3. Changes in accounting policies:

(a) IFRS 15:

IFRS 15, "Revenue from Contracts with Customers" ("IFRS 15") was issued by the IASB in May of 2014 and replaces IAS 18 "Revenue", IAS 11 "Construction Contracts", and related interpretations effective for reporting periods beginning on or after January 1, 2018. The new standard provides a single, principles-based five-step analysis of transactions to determine the nature of an entity's obligation to perform and whether, how much and when revenue is recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and/or timing of revenue recognized.

The Company has adopted IFRS 15 effective January 1, 2018. Tamarack applied IFRS 15 to all of its contracts with customers using the cumulative effect method. Under this method, prior period financial statements have not been restated. Management reviewed the Company's revenue streams and major contracts with customers using the IFRS 15 principles-based five-step model and concluded there were no material changes to earnings or in the timing of when production revenue is recognized. As a result, no adjustments were required in the January 1, 2018 opening balance sheet. The adoption of IFRS 15 does result in new disclosure requirements contained in note 5 of these condensed consolidated interim financial statements.

Tamarack earns revenue from the following major sources:

- Sales from the production of light oil, heavy oil, natural gas and natural gas liquids; and
- Fees charged to third parties for processing and other services (i.e., gas and other product processing, etc.) provided at facilities where Tamarack has an ownership interest.

Revenues from the sale of crude oil, natural gas liquids and natural gas is recognized based on the consideration specified in contracts with customers. Tamarack recognizes revenue when it transfers control of the product to the customer, which is generally when legal title passes to the customer which is when it is physically transferred to the pipeline or other transportation method agreed upon and collection is reasonably assured. The amount of revenue recognized is based on the consideration specified in the contract. Revenues from processing activities are recognized over time as processing occurs, and are generally billed monthly.

The Company evaluates its arrangements with third parties and partners to determine if Tamarack is acting as the principal or as an agent. Tamarack is considered the principal in a transaction when it has primary responsibility for the transaction. If Tamarack acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction.

(b) IFRS 9:

On January 1, 2018, the Company adopted all of the requirements of IFRS 9, “Financial Instruments” (“IFRS 9”) which replaces IAS 39, “Financial Instruments: Recognition and Measurement” (“IAS 39”). The retrospective adoption of IFRS 9 had no material impact to the Company’s condensed consolidated interim financial statements.

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost; fair value through other comprehensive income (“FVOCI”); or fair value through profit or loss (“FVTPL”). The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics. IFRS 9 eliminates the previous IAS 39 categories of held to maturity, loans and receivables and available for sale. IFRS 9 largely retains the existing requirements in IAS 39 for the classification of financial liabilities.

The following table shows the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 as at January 1, 2018 for each class of the Company’s financial assets and financial liabilities:

	Measurement category	
Financial instrument	**IAS 39**	**IFRS 9**
Cash and cash equivalents	Loans and receivables	Amortized cost
Accounts receivable	Loans and receivables	Amortized cost
Financial derivative contracts	Fair value through profit or loss	Fair value through profit or loss
Accounts payable and accrued liabilities	Financial liabilities at amortized cost	Amortized cost
Bank debt	Financial liabilities at amortized cost	Amortized cost

There were no adjustments to the carrying amounts of the Company's financial instruments as a result of the change in classification from IAS 39 to IFRS 9. The Company does not apply hedge accounting.

IFRS 9 replaces the "incurred loss" model in IAS 39 with an "expected credit loss" ("ECL") model. 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. The application of the new expected credit loss model did not have a significant impact on the Company's financial assets.

4. Commodity contracts:

It is the Company's policy to economically hedge some oil and natural gas sales using various financial derivative forward sales contracts and physical sales contracts. The Company does not apply hedge accounting for these contracts. The Company's production is usually sold using "spot" or near term contracts, with prices fixed at the time of transfer of custody or based on a monthly average market price. The Company, however, may give consideration in certain circumstances to the appropriateness of entering into long-term, fixed price marketing contracts. The Company does not enter into commodity contracts other than to meet its expected sales requirements.

All financial derivative contracts are classified as fair value through profit and loss and are recorded on the balance sheet at fair value. The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and level 2 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 collars is based on option models that use level 2 inputs, being published information with respect to volatility, prices and interest rates. The derivatives are valued at fair value through profit or loss and therefore the carrying amount equals fair value.

At March 31, 2018, 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	300 bbls/day	April 1, 2018 – June 30, 2018	WTI fixed price	Cdn $80.17	$(86)
Crude oil	5,200 bbls/day	April 1, 2018 – June 30, 2018	WTI fixed price	US $55.49	$(4,840)
Crude oil	5,200 bbls/day	July 1, 2018 – September 30, 2018	WTI fixed price	US $56.08	$(3,740)
Crude oil	5,100 bbls/day	October 1, 2018 – December 31, 2018	WTI fixed price	US $57.17	$(4,110)
Crude oil	1,500 bbls/day	January 1, 2019 – March 31, 2019	WTI fixed price	US $59.65	$(119)
Crude oil	500 bbls/day	January 1, 2019 – December 31, 2019	WTI written call option	US $52.00	$(2,008)
Foreign exchange	2,515,000 US$/mth	April 1, 2018 – June 30, 2018	Exchange rate	Cdn $1.2836	$(79)
Foreign exchange	4,335,000 US$/mth	July 1, 2018 – September 30, 2018	Exchange rate	Cdn $1.2819	–
Foreign exchange	1,370,000 US$/mth	October 1, 2018 – December 31, 2018	Exchange rate	Cdn $1.2844	$6
					$(14,976)

At March 31, 2018, the commodity contracts were fair valued with a liability of $14,976 (December 31, 2017 - $7,477 liability) recorded on the balance sheet and an unrealized loss of $7,499 recorded in earnings for the three months ended March 31, 2018 (December 31, 2017 - $3,495 unrealized gain).

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement, the realized benefit or loss is recognized in oil and natural gas revenue. At March 31, 2018, the Company held the following physical commodity contracts.

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,050 bbls/day	April 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
Natural gas	10,000 GJ/day	April 1, 2018 – April 30, 2018	AECO fixed price	Cdn $1.47

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)	**March 31, 2018**	December 31, 2017
Risk management contracts		
Current asset	**$–**	$1,941
Current liability	**(13,470)**	(7,936)
Long-term liability	**(1,506)**	(1,482)
Balance, end of the period	**$(14,976)**	$(7,477)

Since March 31, 2018, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	300	October 1, 2018 – December 31, 2018	WTI fixed price	US $62.05
Crude oil	900	January 1, 2019 – March 31, 2019	WTI fixed price	US $62.64
Crude oil	300	April 1, 2019 – June 30, 2019	WTI fixed price	US $61.65

5. Revenue:

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

Production 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 production 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 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. Production revenues are normally collected on the business day nearest the 25th day of the month following production.

The Company’s production 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; 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 marketing production to numerous oil and natural gas marketers under customary industry sale and payment terms. As at March 31, 2018, production revenue was sold to customers, of which four customers account for $29.8 million of the accounts receivable at March 31, 2018. Of the production revenue, 0% resulted from fixed price contracts, and 100% resulted from a transaction price based on the index price in the transaction month.

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

Three months ended March 31, ($ thousands)	**2018**	2017
Light oil	**$81,534**	$44,760
Heavy oil	**1,218**	1,944
Natural gas	**5,474**	4,238
Natural gas liquids	**10,510**	11,928
Oil and natural gas revenue	**98,736**	62,870
Processing income	**336**	344
Total revenue	**$99,072**	$63,214

Refer to note 4 for a listing of physical delivery contracts as at March 31, 2018.

Included in accounts receivable at March 31, 2018 was $35.4 million (December 31, 2017 - $32.0 million) of accrued production revenue related to deliveries for the month then ended. There were no significant adjustments for prior period accrued production revenue reflected in the current period. As at March 31, 2018, the Company did not have any contracts for the sale of its future production beyond one year in term, except certain natural gas contracts that expire in 2022.

6. Property, plant and equipment:

($ thousands)	Oil and natural gas interests	Other assets	Total
Cost:			
Balance at January 1, 2017	$899,170	$1,034	$900,204
Corporate acquisition	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 7)	8,980	–	8,980
Disposals	(5,378)	–	(5,378)
Balance at December 31, 2017	1,624,550	1,368	1,625,918
Property acquisition	2,790	–	2,790
Cash additions	69,341	66	69,407
Decommissioning costs	3,603	–	3,603
Stock-based compensation	524	–	524
Transfer from exploration and evaluation assets (note 7)	894	–	894
Disposals	(128)	–	(128)
Balance at March 31, 2018	$1,701,574	$1,434	$1,703,008

Depletion, depreciation and impairment losses:			
Balance at January 1, 2017	$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
Depletion and depreciation	43,228	56	43,284
Balance at March 31, 2018	$506,197	$733	$506,930

	Oil and natural gas interests	Other assets	Total
Carrying amounts:			
At December 31, 2017	$1,161,581	$691	$1,162,272
At March 31, 2018	$1,195,377	$701	$1,196,078

The calculation of depletion at March 31, 2018 includes estimated future development costs of $669,790 (December 31, 2017 – $694,759) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $46,585 (December 31, 2017 – $44,825).

Subsequent to March 31, 2018, the Company disposed of its interest in certain oil and gas infrastructure for $5,000 and has entered into an operating lease regarding certain oil and gas infrastructure for a rental fee of $0.05 million per month for 96 months.

7. Exploration and evaluation assets:

($ thousands)	Total
Cost:	
Balance at January 1, 2017	$23,856
Additions	9,092
Transfer to property, plant and equipment (note 6)	(8,980)
Balance at December 31, 2017	23,968
Additions	223
Transfer to property, plant and equipment (note 6)	(894)
Balance at March 31, 2018	$23,297
Amortization and impairment:	
Balance at January 1, 2017	$21,353
Amortization	787
Balance at December 31, 2017	22,140
Amortization	174
Balance at March 31, 2018	$22,314

	Total
Carrying amounts:	
At December 31, 2017	$1,828
At March 31, 2018	$983

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.

8. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted and uninflated amount of cash flows required to settle its decommissioning obligations to be approximately $180.9 million at March 31, 2018 (December 31, 2017 – $177.8 million), which is expected to be incurred between 2018 and 2041. A risk-free rate of 2.3% (December 31, 2017 – 2.3%) and an inflation rate of 2% (December 31, 2017 – 2%) is used to calculate the present value of the decommissioning obligations at March 31, 2018 as presented in the table below:

($ thousands)	**Three months ended March 31, 2018**	Year ended December 31, 2017
Balance, beginning of the period	**$177,793**	$112,115
Liabilities incurred	**3,603**	12,689
Liabilities acquired	**–**	19,207
Change in estimates	**–**	1,815
Change in discount rate on acquisition	**–**	29,201
Expenditures	**(53)**	(898)
Liabilities disposed	**(134)**	(77)
Accretion	**1,007**	3,741
Balance, end of the period	**$182,216**	$177,793

9. Supplemental cash flow information:

Changes in non-cash working capital consists of:

Three months ended March 31, ($ thousands)	**2018**	2017
Source/(use) of cash:		
Accounts receivable	**$(1,219)**	$(16,726)
Prepaid expenses and deposits	**(287)**	(1,672)
Accounts payable and accrued liabilities	**13,197**	41,386
Working capital acquired	**–**	29,167
	$11,691	$52,155
Related to operating activities	**$1,793**	$(1,797)
Related to investing activities	**$9,898**	$53,952

The following are included in cash flows from operating activities:

Three months ended March 31, ($ thousands)	**2018**	2017
Interest paid in cash	**$1,841**	$1,420

10. Share capital:

At March 31, 2018 the Company was authorized to issue an unlimited number of common shares and preferred shares without nominal or par value.

During the three months ended March 31, 2018, 156,000 stock options at $2.41 per share were exercised for gross proceeds of $376,000. There were also 98,000 restricted share awards converted to common shares.

11. Income per share:

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

Three months ended March 31, ($ thousands, except per share amounts)	**2018**	2017
Net income	**$3,294**	$2,290
Weighted average shares - basic	**228,621**	217,655
Weighted average shares - diluted	**231,713**	219,679
Net income per share-basic	**$ 0.01**	$ 0.01
Net income per share-diluted	**$ 0.01**	$ 0.01

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three months ended March 31, 2018, 5.9 million stock options, preferred shares and restricted stock units were included in the diluted weighted average number of shares outstanding. For the three months ended March 31, 2017, 2.0 million stock options, preferred shares and restricted stock units were included in the diluted weighted average numbers of shares outstanding.

12. Bank debt:

The Company currently has available a revolving credit facility in the amount of $270 million and a $20 million operating facility (collectively the "Facility") with a syndicate of lenders. The Facility, totaling $290 million, 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.

The total interest rate on the Facility is determined through a pricing grids 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 net debt-to-cash-flow ratio. Interest on banker's acceptance ("BA") notes will vary based on a BA pricing grid 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%. Interest on prime lending varies based on a prime rate pricing grid 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 million 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 25, 2018.

At March 31, 2018, the Company had utilized the Facility in the amount of $165.8 million. The interest rate applicable to the drawn amounts as of this date was 4.49%. As at March 31, 2018, the Company had letter of guarantees outstanding in the amount of $0.2 million 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 March 31, 2018, the Company is in compliance with all covenants.

13. Share-based payments:

(a) Preferred share plan:

There are 1,155,000 preferred shares of Tamarack Acquisition Corp. outstanding which are exchangeable into 1,111,000 common shares of the Company (December 31, 2017 – 1,111,000). The preferred shares are fully vested at March 31, 2018 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 three months ended March 31, 2018 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 22.9 million options or restricted share units to its employees, directors and consultants of which 10.4 million 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 195,000 options granted during the three months March 31, 2018.

The fair value of each option granted during the three months ended March 31, 2018 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:

	2018
Risk free rate (%)	**1.94**
Expected volatility (%)	**80**
Expected life (years)	**5**
Forfeiture rate (%)	**–**
Dividend ($ per share)	**–**
Fair value at grant date ($ per option)	**1.78**

The number and weighted average exercise prices of stock options under the plan are as follows:

	Number of options (thousands)	Weighted average exercise price
Outstanding, January 1, 2017	5,327	$ 3.52
Granted	140	3.01
Exercised	(812)	1.98
Expired	(99)	2.79
Outstanding, December 31, 2017	4,556	$ 3.79
Granted	195	2.62
Exercised	(156)	2.41
Outstanding, March 31, 2018	**4,595**	**$ 3.79**

The range of exercise prices of stock options outstanding and exercisable at March 31, 2018 is as follows:

	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	955	$2.71	3.3	463	$2.73
$ 3.01 – 5.00	3,174	$3.66	1.7	2,494	$3.72
$ 5.01 – 6.82	466	$6.82	1.4	466	$6.82
$ 1.86 – 6.82	**4,595**	**$3.79**	**2.0**	**3,423**	**$4.01**

(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. There were 80,000 restricted stock units granted during the three months ended March 31, 2018.

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, 2017	3,063
Granted	2,785
Exercised	(28)
Forfeited	(2)
Outstanding, December 31, 2017	5,818
Granted	80
Exercised	(98)
Outstanding, March 31, 2018	**5,800**
Exercisable, March 31, 2018	**1,707**

14. Commitments:

The following table summarizes the Company's commitments as at March 31, 2018:

($ thousands)	2018	2019	2020	2021	2022	2023	2024+
Office lease	407	542	263	–	–	–	–
Take or pay commitments(1)	657	2,205	2,256	2,294	2,340	2,396	–
Rental fee(2)	4,306	5,741	5,741	5,741	3,870	1,999	1,142
Gas transportation(3)	1,836	730	229	76	–	–	–
Total	7,206	9,218	8,849	8,111	6,210	4,395	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 9 months. Pipeline commitment to deliver a minimum of 636 m3/d of crude oil/condensate subject to a take-or-pay provision of $9.00/m3. The term starts on January 1, 2019 and lasts for 60 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.

15. Subsequent event:

On April 4, 2018, Tamarack announced that the Toronto Stock Exchange had accepted the notice of Tamarack's intention to commence a normal course issuer bid ("NCIB"). Under the NCIB Tamarack intends to acquire up to 8.6 million common shares of the Company over a period of twelve months commencing on April 6, 2018. The NCIB will expire no later than April 5, 2019. Any common shares that are purchased under the NCIB will be cancelled upon their purchase by Tamarack. As of May 9, 2018, the Company spent $836,827 to purchase and cancel 243,500 outstanding common shares under the NCIB.

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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