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 and nine months ended September 30, 2018 and 2017. This MD&A is dated and based on information available on November 7, 2018 and should be read in conjunction with the unaudited condensed consolidated interim financial statements and the notes thereto for the three and nine months ended September 30, 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 19. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

Q3 2018 Financial and Operating Highlights

- Achieved record corporate production in Q3/18 of 24,765 boe/d, up 4% over Q2/18 volumes of 23,853 boe/d and up 21% over Q3/17 volumes of 20,541 boe/d.
- Oil and natural gas liquids ("NGL") weighting was 66% in Q3/18 compared to 63% in Q2/18 and 59% in Q3/17. The 12% increase from Q3/17 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 97% to $68.6 million in Q3/18 ($0.30 per share basic and $0.29 per share diluted), from $34.8 million in Q3/17 ($0.15 per share basic and diluted).
- Net production and transportation expenses in Q3/18 were 8% lower at $10.38/boe compared to $11.26/boe in Q3/17.
- Operating netbacks (excluding the effects of hedging) increased by 94% to $36.61/boe in Q3/18 from $18.84/boe in Q3/17 primarily due to the 47% increase in the combined average realized prices for oil and NGL, the 12% increase in oil and NGL weighting and the 8% decrease in net production and transportation expenses.
- Invested $78.1 million in total capital expenditures during the third quarter of 2018, which was directed to the drilling 43 (42.4 net) Viking oil wells, three (1.8 net) Cardium oil wells, three (3.0 net) Penny oil wells and four (4.0 net) Redwater oil wells plus one exploratory vertical stratigraphic well.

Of the wells drilled in the quarter, the 18 (17.8 net) Viking oil wells and one (1.0 net) Penny well will be brought on production in the fourth quarter of 2018. In addition to the third quarter drilling program, the Company also completed and brought on production wells that were drilled in late Q2/18 including 18 (17.8 net) Viking oil wells, six (6.0 net) Cardium oil wells and one (1.0 net) Penny oil.

Production

Quarter-over-Quarter

	Q3 2018	Q2 2018	% change
Production			
Light oil (bbls/d)	**14,417**	13,242	9
Heavy oil (bbls/d)	**621**	527	18
Natural gas liquids (bbls/d)	**1,403**	1,355	4
Natural gas (mcf/d)	**49,943**	52,376	(5)
Total (boe/d)	**24,765**	23,853	4
Percentage of oil and natural gas liquids	**66%**	63%	5

Average production for the third quarter of 2018 increased 4% over the previous quarter and reflects the positive impact of third quarter drilling plus a full quarter of production from wells drilled in the second quarter of 2018. Contributing to this increase was an additional 2,659 boe/d from the Veteran development program (85% oil and NGL), 410 boe/d from the Penny development program (95% oil and NGL), 232 boe/d from the Redwater development program (99% oil and NGL) and 182 boe/d from Wilson Creek/Alder Flats (71% oil and NGL). These gains were partially offset by expected declines from base production.

The Company's oil and NGL weighting was 66% for the third quarter of 2018 an increase from 63% for the second quarter of 2018. For the remainder of 2018, the Company expects its oil and NGL weighting to remain between 65% to 67%. The liquids weighting going forward will ultimately depend on timing of production additions from the higher oil-weighted areas of Veteran, Wilson Creek, Penny and Redwater relative to additions from the higher natural gas-weighted area of Alder Flats.

Year-over-Year

	Three months ended September 30,			Nine months ended September 30,		
	2018	2017	% change	**2018**	2017	% change
Production						
Light oil (bbls/d)	**14,417**	10,108	43	**13,636**	9,168	49
Heavy oil (bbls/d)	**621**	603	3	**484**	514	(6)
Natural gas liquids (bbls/d)	**1,403**	1,499	(6)	**1,369**	1,576	(13)
Natural gas (mcf/d)	**49,943**	49,987	–	**51,393**	47,860	7
Total (boe/d)	**24,765**	20,541	21	**24,055**	19,235	25
Percentage of oil and natural gas liquids	**66%**	59%	12	**64%**	59%	8

Compared to the prior year, average production for the third quarter of 2018 increased by 21% and average production for the first nine months of 2018 increased by 25%. These increases are attributable to the successful Veteran, Wilson Creek, Penny and Redwater development drilling program through 2017 and the first nine months of 2018, partially offset by expected declines from base production.

Petroleum and Natural Gas Sales

Quarter-over-Quarter

	Q3 2018	Q2 2018	% change
Revenue ($ thousands)			
Oil and NGL	**$111,636**	$100,002	12
Natural gas	**7,498**	7,857	(5)
Total	**$119,134**	$107,859	10
Average realized wellhead price			
Light oil ($/bbl)	**76.98**	75.29	2
Heavy oil ($/bbl)	**69.33**	70.17	(1)
Natural gas liquids ($/bbl)	**43.64**	45.90	(5)
Combined average oil and NGL ($/boe)	**73.81**	72.66	2
Natural gas ($/mcf)	**1.63**	1.65	(1)
Revenue ($/boe)	**52.29**	49.69	5
Benchmark pricing:			
West Texas Intermediate (US$/bbl)	**69.54**	67.88	2
Edmonton Par (Cdn$/bbl)	**77.26**	78.90	(2)
Hardisty Heavy (Cdn$/bbl)	**54.34**	64.40	(16)
AECO daily index (Cdn$/mcf)	**1.18**	1.18	–
AECO monthly index (Cdn$/mcf)	**1.35**	1.02	32

Revenue from oil, natural gas and NGL sales was 10% higher in the third quarter of 2018 compared to the second quarter of 2018. Stronger revenue quarter-over-quarter is attributable to the increase in production volumes and higher wellhead pricing for crude oil and NGL, partially offset by lower natural gas pricing.

WTI crude oil markets remained strong during the third quarter of 2018, exiting the quarter at a spot price of US$76.57/bbl. The average third quarter WTI price of US$69.54/bbl was 2% higher than the average second quarter price of US$67.88/bbl. Despite these improvements to WTI pricing and the continued weakness in the Canadian dollar through the summer, the third quarter Edmonton Par index averaged $77.26/bbl, a 2% reduction over the second quarter average of $78.90/bbl. This decrease was due largely to the widening of the WTI/Edmonton Par light oil differential during the quarter as a result of continued issues related to market oversupply and Canadian infrastructure restrictions. These market challenges resulted in a third quarter average differential of US$6.82/bbl versus US$5.46/bbl in the second quarter of 2018. Even with the decrease in the Edmonton Par index, Tamarack's realized light oil wellhead price for the three months ended September 30, 2018 increased 2% to $76.98/bbl from $75.29/bbl in the previous quarter, due in part to previously hedged WTI/Edmonton Par differentials coupled with the increased proportion of production represented by high-quality Viking light oil. Tamarack has a light oil WTI/Edmonton Par physical hedge of 1,500 bbls/d at US$5.50/bbl for the remainder of 2018. Subsequent to quarter end, continued pricing pressures have resulted in light oil differentials of more than US$30/bbl resulting in further underperformance of the Edmonton Par price relative to WTI. While the duration and magnitude of these extreme price conditions are difficult to predict, Tamarack is committed to conservatively planning around future oil prices and continues to explore ways to mitigate and manage market risk.

Realized NGL prices were down slightly in the third quarter of 2018, decreasing 5% to $43.64/bbl from $45.90/bbl in the second quarter of 2018. The increase in WTI prices through the quarter led to an increase in butane and condensate prices, as those contracts are priced relative to WTI. However, an increase in the proportionate contribution of lower-value propane resulted in an overall decrease in the average NGL price for the quarter.

Tamarack's realized natural gas price remained relatively flat at $1.63/mcf in the third quarter of 2018 compared to $1.65/mcf in the previous quarter. Similarly, the AECO daily benchmark price remained flat quarter-over-quarter at $1.18/mcf. While the percent changes were similar, Tamarack's realized natural gas price was higher than the benchmark on a financial value basis, due largely to the Company's continued efforts to diversify its natural gas market exposure.

The Company's gas market exposure is reflected below:

Natural Gas Market	**Percentage Exposure (as at September 30, 2018)**	**Percentage Exposure (as at November 1, 2018)**
AECO Daily (5A)	21.4	0.4
AECO Daily (5A) + premium (SK)	19.2	21.7
Dawn	7.9	8.9
Chicago	7.9	8.9
Michigan City Gate	7.9	8.9
Malin	15.7	17.7
Waddington	nil	11.3
NYMEX (Physical Basis Swap)	20.0	22.2
	100%	100%

Natural gas prices continue to be under pressure as oversupply in the province combined with restrictions on take-away capacity are expected to continue creating volatility and resulting in depressed prices for the AECO daily index for the remainder of 2018. Tamarack benefited from additional gas sales contracts with a third party that came into effect on April 1, 2018 and continue until 2022, offering further diversification of the Company's natural gas price exposure. Through the third quarter of 2018, more than 50% of Tamarack's total natural gas production was priced in alternate US markets, including Malin, Chicago, Michigan Consolidated, Dawn and NYMEX daily index pricing less transportation tolls or fixed basis fees. In addition to the diversification in place during the third quarter, effective November 1, 2018 through 2030, an additional 10% of the Company's current gas production will be exposed to an alternate US market. Tamarack will continue to explore alternatives to minimize exposure to Alberta gas market volatility.

Year-over-Year

	Three months ended September 30,			Nine months ended September 30,		
	2018	2017	% change	**2018**	2017	% change
Revenue ($ thousands)						
Oil and NGL	**$111,636**	$56,493	98	**$299,864**	$161,084	86
Natural gas	**7,498**	7,434	1	**25,865**	32,428	(20)
Total	**$119,134**	$63,927	86	**$325,729**	$193,512	68
Average realized wellhead price						
Light oil ($/bbl)	**76.98**	53.43	44	**73.76**	56.89	30
Heavy oil ($/bbl)	**69.33**	46.26	50	**64.29**	45.03	43
Natural gas liquids ($/bbl)	**43.64**	30.76	42	**44.88**	28.74	56
Combined average oil and NGL ($/boe)	**73.81**	50.29	47	**70.91**	52.41	35
Natural gas ($/mcf)	**1.63**	1.62	1	**1.84**	2.48	(26)
Revenue ($/boe)	**52.29**	33.83	55	**49.60**	36.85	35
Benchmark pricing:						
West Texas Intermediate (US$/bbl)	**69.54**	48.16	44	**66.80**	50.04	33
Edmonton Par (Cdn$/bbl)	**77.26**	57.03	35	**76.17**	60.66	26
Hardisty Heavy (Cdn$/bbl)	**54.34**	47.20	15	**55.24**	49.67	11
AECO daily index (Cdn$/mcf)	**1.18**	1.45	(19)	**1.47**	2.30	(36)
AECO monthly index (Cdn$/mcf)	**1.35**	2.03	(33)	**1.40**	2.48	(44)

Revenue from oil, natural gas and NGL sales for the three and nine months ended September 30, 2018 increased by 86% and 68%, respectively, compared to the same periods in 2017, primarily due to increased production volumes and higher 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 September 30, 2018, the Company held derivative commodity and foreign exchange contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	7,100 bbls/day	October 1, 2018 – December 31, 2018	WTI fixed price	US $59.91
Crude oil	4,000 bbls/day	January 1, 2019 – March 31, 2019	WTI fixed price	US $63.28
Crude oil	3,500 bbls/day	April 1, 2019 – June 30, 2019	WTI fixed price	US $65.28
Crude oil	2,700 bbls/day	July 1, 2019 – September 30, 2019	WTI fixed price	US $64.41
Crude oil	2,100 bbls/day	October 1, 2019 – December 31, 2019	WTI fixed price	US $63.17
Crude oil	500 bbls/day	January 1, 2020 – March 31, 2020	WTI fixed price	US $65.45
Crude oil	500 bbls/day	January 1, 2019 – December 31, 2019	WTI written call option	US $52.00
Foreign exchange	9,000,000 US$/mth	October 1, 2018 – December 31, 2018	Exchange rate	Cdn $1.2937
Foreign exchange	6,000,000 US$/mth	January 1, 2019 – March 31, 2019	Exchange rate	Cdn $1.3013
Foreign exchange	4,000,000 US$/mth	April 1, 2019 – June 30, 2019	Exchange rate	Cdn $1.2955
Foreign exchange	4,000,000 US$/mth	July 1, 2019 – September 30, 2019	Exchange rate	Cdn $1.2955
Foreign exchange	3,000,000 US$/mth	October 1, 2019 – December 31, 2019	Exchange rate	Cdn $1.2985

At September 30, 2018, the commodity and foreign exchange contracts were fair valued with a liability of $25.1 million (December 31, 2017 - $7.5 million liability) recorded on the balance sheet and an unrealized loss of $17.6 million recorded in earnings for the nine months ended September 30, 2018 (December 31, 2017 - $3.5 million unrealized gain). During the third quarter of 2018 the Company realized a $9.5 million loss on financial instruments and an $18.0 million loss for the nine months ended September 30, 2018, compared to a gain of $4.0 million and $2.4 million for the same periods in 2017, respectively.

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 September 30, 2018, the Company held the following physical commodity contracts.

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	5,000 mmbtu/day	October 1, 2018 – October 31, 2018	AECO/Henry Hub differential	Index – US $1.88
Natural gas	10,000 mmbtu/day	November 1, 2018 – March 31, 2019	AECO/Henry Hub differential	Index – US $1.43
Natural gas	2,500 mmbtu/day	January 1, 2019 – March 31, 2019	AECO/Henry Hub differential	Index – US $1.42
Natural gas	10,000 mmbtu/day	April 1, 2019 – October 31, 2019	AECO/Henry Hub differential	Index – US $1.60
Natural gas	2,500 mmbtu/day	November 1, 2019 – March 31, 2020	AECO/Henry Hub differential	Index – US $1.33
Crude oil	1,500 bbls/day	October 1, 2018 – December 31, 2018	WTI/Edm Differential	US $5.50

Since September 30, 2018, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	200 bbls/day	January 1, 2020 – March 31, 2020	WTI fixed price	US $70.75
Foreign exchange	2,000,000 US$/mth	April 1, 2019 – June 30, 2019	Exchange rate	Cdn $1.3045
Foreign exchange	1,000,000 US$/mth	July 1, 2019 – September 30, 2019	Exchange rate	Cdn $1.3017

Royalties

Quarter-over-Quarter

	Q3 2018	Q2 2018	% change
Royalty expenses ($ thousands)	**$12,075**	$10,986	10
$/boe	**5.30**	5.06	5
percent of sales	**10**	10	–

Royalties as a percentage of revenue were comparable for the third and second quarters of 2018.

Year-over-Year

	Three months ended September 30,			Nine months ended September 30,		
	2018	2017	% change	**2018**	2017	% change
Royalty expenses ($ thousands)	**$12,075**	$7,043	71	**$33,999**	$20,670	64
$/boe	**5.30**	3.73	42	**5.18**	3.94	31
percent of sales	**10**	11	(9)	**10**	11	(9)

Royalties as a percentage of revenue were comparable for both the three and nine months ended September 30, 2018 compared to the same periods in 2017. The Company expects royalty rates as a percentage of revenue to remain in the 10% to 12% range for the remainder of 2018 based on current commodity price levels.

Net Production and Transportation Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q3 2018**	Q2 2018	% change
Production and transportation expenses	**$23,813**	$22,465	6
Less: processing income (expense)	**170**	(274)	(162)
Total net production and transportation expenses	**$23,643**	$22,739	4
Total ($/boe)	**$10.38**	$10.48	(1)

Net production and transportation expenses per boe for the third quarter of 2018 decreased 1% compared to the second quarter of 2018, due to increased production. On an absolute basis, overall costs were higher in the third quarter of 2018 compared to the second quarter of 2018 due to the higher production. Production and transportation expenses on a per boe basis decreased in the third quarter due to the effect of fixed costs being spread across higher volumes in Veteran. The Company expects production and transportation expenses to average between $10.30/boe and $10.40/boe in the fourth quarter of 2018.

Year-over-Year

	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2018**	2017	% change	**2018**	2017	% change
Production and transportation expenses	**$23,813**	$21,827	9	**$69,392**	$61,117	14
Less: processing income	**170**	556	(69)	**232**	696	(67)
Total net production and transportation expenses	**$23,643**	$21,271	11	**$69,160**	$60,421	14
Total ($/boe)	**$10.38**	$11.26	(8)	**$10.53**	$11.51	(9)

For both the three and nine months ended September 30, 2018, net production and transportation expenses per boe were lower compared to the same periods in 2017 as a result of increased production volumes from the Veteran area, where production expenses are lower than the corporate average. In addition, higher volumes spread 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 periods.

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)	**Q3 2018**	Q2 2018	% change
Average realized sales	**$52.29**	$49.69	5
Royalty expenses	**(5.30)**	(5.06)	5
Net production and transportation expenses	**(10.38)**	(10.48)	(1)
	36.61	34.15	7
Realized commodity hedging loss	**(4.16)**	(3.36)	24
Operating netback	**$32.45**	$30.79	5

Tamarack recorded an improvement in operating netbacks for the third quarter of 2018 relative to the prior quarter. This improvement was due to higher oil and NGL weighting and higher realized oil prices in Q3 2018 over Q2 2018 and lower net production and transportation expenses, offset by an increase in royalties and realized commodity hedging loss.

Year-over-Year

	Three months ended September 30,			Nine months ended September 30,		
($/boe)	**2018**	2017	% change	**2018**	2017	% change
Average realized sales	**$52.29**	$33.83	55	**$49.60**	$36.85	35
Royalty expenses	**(5.30)**	(3.73)	42	**(5.18)**	(3.94)	31
Net production and transportation expenses	**(10.38)**	(11.26)	(8)	**(10.53)**	(11.51)	(9)
	36.61	18.84	94	**33.89**	21.40	58
Realized commodity hedging gain (loss)	**(4.16)**	2.11	(297)	**(2.75)**	0.46	(698)
Operating netback	**$32.45**	$20.95	55	**$31.14**	$21.86	42

For the three and nine months ended September 30, 2018, operating netbacks increased 55% and 42%, over the same respective periods in 2017, supported by the Company's higher oil and NGL weighting, improved realized prices for crude oil and NGL and lower net production and transportation expenses per boe. These gains were partially offset by lower realized natural gas prices, higher royalties and realized commodity hedging losses on financial derivative contracts occurring in 2018.

General and Administrative ("G&A") Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q3 2018**	Q2 2018	% change
Gross costs	**$4,377**	$4,191	4
Capitalized costs and recoveries	**(1,082)**	(817)	32
General and administrative costs	**$3,295**	$3,374	(2)
Total ($/boe)	**$1.45**	$1.55	(6)

Gross and net G&A expenses remained consistent between the third quarter of 2018 and the second quarter of 2018. G&A expenses on a per boe basis decreased quarter-over-quarter due to the 4% increase in production.

Year-over-Year

($ thousands, except per boe)	Three months ended September 30, 2018	2017	% change	Nine months ended September 30, 2018	2017	% change
Gross costs	**$4,377**	$3,889	13	**$12,792**	$11,550	11
Capitalized costs and recoveries	**(1,082)**	(832)	30	**(2,744)**	(2,503)	10
General and administrative costs	**$3,295**	$3,057	8	**$10,048**	$9,047	11
Total ($/boe)	**$1.45**	$1.62	(10)	**$1.53**	$1.72	(11)

Gross G&A costs increased in the three and nine months ended September 30, 2018, compared to the same periods in 2017, due to staffing increases following the Spur Viking acquisition (the "Viking Acquisition"). Net G&A costs per boe for both the three and nine months ended September 30, 2018 were lower than the same periods in 2017 due to scale efficiencies associated with the increase in production.

Stock-Based Compensation Expenses

Quarter-over-Quarter

($ thousands, except per boe)	Q3 2018	Q2 2018	% change
Gross costs	**$4,175**	$2,218	88
Capitalized costs	**(1,177)**	(757)	55
Total stock-based compensation	**$2,998**	$1,461	105
Total ($/boe)	**$1.32**	$0.67	97

Stock-based compensation expense related to stock options ("options") and restricted share unit awards ("RSUs") was higher in the third quarter as compared to the second quarter due to the granting of RSU's late in the second quarter of 2018. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

Year-over-Year

($ thousands, except per boe)	Three months ended September 30, 2018	2017	% change	Nine months ended September 30, 2018	2017	% change
Gross costs	**$4,175**	$1,541	171	**$8,431**	$4,740	78
Capitalized costs	**(1,177)**	(489)	141	**(2,458)**	(1,517)	62
Total stock-based compensation	**$2,998**	$1,052	185	**$5,973**	$3,223	85
Total ($/boe)	**$1.32**	$0.56	136	**$0.91**	$0.61	49

Stock-based compensation expense related to options and RSUs was higher for the three and nine months ended September 30, 2018 relative to the same periods in 2017, as higher staffing levels stemming from Tamarack's production growth through 2017 resulted in more RSUs being granted at the end of the fourth quarter of 2017 and the second quarter of 2018. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

For the nine months ended September 30, 2018, the Company issued 0.2 million options at a weighted average exercise price of $2.62 per share and issued 2.4 million RSUs. Additionally, 1.5 million options at $3.21 per share were exercised for total gross proceeds of $4.9 million, while 0.6 million RSUs were settled.

Interest Expense

Quarter-over-Quarter

($ thousands, except per boe)	**Q3 2018**	Q2 2018	% change
Interest on bank debt	**$2,063**	$2,462	(16)
Total ($/boe)	**$0.91**	$1.13	(19)
Average drawings on bank debt	**$155,131**	$156,504	(1)

Interest expense was lower in the third quarter of 2018 compared to the previous quarter, due to fees associated with the renewal of Tamarack's credit facility occurring in the second quarter of 2018 and a lower average amount drawn quarter-over-quarter on the revolving credit facility.

Year-over-Year

	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2018**	2017	% change	**2018**	2017	% change
Interest on bank debt	**$2,063**	$1,776	16	**$6,366**	$4,996	27
Total ($/boe)	**$0.91**	$0.94	(3)	**$0.97**	$0.95	2
Average drawings on bank debt	**$155,131**	$156,055	(1)	**$158,769**	$142,706	11

Interest expense for the three months ended September 30, 2018 was higher than the same period in 2017 due to an interest rate increase occurring at the beginning of the third quarter of 2018 compared to an interest rate increase occurring at the end of the third quarter of 2017.

Interest expense for the nine months ended September 30, 2018 was higher than the same period in 2017. This is attributable to an interest rate increase that occurred at the beginning of the third quarter of 2018, coupled with a higher average amount drawn in the nine months ended September 30, 2018 on the revolving credit facility associated with increased capital spending year-over-year.

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 ("E&E") assets is also amortized over its term to expiry, which is charged to DDA&A expense.

Quarter-over-Quarter

($ thousands, except per boe)	**Q3 2018**	Q2 2018	% change
Depletion and depreciation	**$45,409**	$43,307	5
Amortization of undeveloped leases	**282**	294	(4)
Accretion	**1,041**	1,015	3
Total	**$46,732**	$44,616	5
Depletion and depreciation ($/boe)	**$19.93**	$19.95	–
Amortization ($/boe)	**0.12**	0.14	(14)
Accretion ($/boe)	**0.46**	0.47	(2)
Total ($/boe)	**$20.51**	$20.56	–

DDA&A expense per boe for the third quarter of 2018 was comparable to the second quarter of 2018. On an absolute basis, DDA&A expense was higher quarter-over-quarter due to the increase in production.

Year-over-Year

	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2018**	2017	% change	**2018**	2017	% change
Depletion and depreciation	**$45,409**	$38,746	17	**$132,000**	$106,293	24
Amortization of undeveloped leases	**282**	197	43	**750**	590	27
Accretion	**1,041**	892	17	**3,063**	2,706	13
Total	**$46,732**	$39,835	17	**$135,813**	$109,589	24
Depletion and depreciation ($/boe)	**$19.93**	$20.50	(3)	**$20.10**	$20.24	(1)
Amortization ($/boe)	**0.12**	0.10	20	**0.11**	0.11	–
Accretion ($/boe)	**0.46**	0.47	(2)	**0.47**	0.52	(10)
Total ($/boe)	**$20.51**	$21.07	(3)	**$20.68**	$20.87	(1)

For the three and nine months ended September 30, 2018, DDA&A expense per boe was lower relative to the same periods in 2017. The decrease was due to an internal estimate of reserves added as a result of the initiation of a water-flood project in the Veteran area, partially offset by higher facility and infrastructure capital spent at Veteran to complete the first and second phase battery expansions through the second half of 2017 and in Q1 2018, respectively. On an absolute basis, DDA&A expense was higher for the three and nine months ended September 30, 2018 due to an increase in production volumes.

Income Taxes

The Company did not incur any cash tax expense in the three and nine months ended September 30, 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 and nine months ended September 30, 2018, deferred income tax expense of $5.9 million and $9.4 million, respectively, were recognized compared to a deferred income tax recovery of $2.1 million in the third quarter of 2017 and a deferred tax expense of $0.7 million for the nine months ended September 30, 2017.

Adjusted Operating Field Netback and Net Income (Loss)

Quarter-over-Quarter

($ thousands, except per share)	**Q3 2018**	Q2 2018	% change
Income before taxes	**$18,923**	$4,731	300
Depletion, depreciation and amortization	**45,691**	43,601	5
Stock-based compensation	**2,998**	1,461	105
Accretion expense on decommissioning obligations	**1,041**	1,015	3
Unrealized loss (gain) on financial instruments	**(74)**	10,197	(101)
Adjusted operating field netback	**$68,579**	$61,005	12
Per share - basic	**$0.30**	$0.27	11
Per share - diluted	**$0.29**	$0.26	12
Net income	**$13,004**	$3,060	325
Per share - basic	**$0.06**	$0.01	500
Per share - diluted	**$0.06**	$0.01	500

The adjusted operating field netback (previously referred to as “adjusted funds flow”; see “Non-IFRS Measures”) during the third quarter of 2018 was higher than the second quarter of 2018 primarily due to an increase in production volumes, an increase in oil and NGL weighting and 10% higher revenues from oil and natural gas.

The Company recorded net income of $13.0 million ($0.06 per share basic and diluted) during the three months ended September 30, 2018, compared to net income of $3.1 million ($0.01 per share basic and diluted) for the previous quarter.

Year-over-Year

	Three months ended September 30,			Nine months ended September 30,		
($ thousands, except per boe)	**2018**	2017	% change	**2018**	2017	% change
Income (loss) before taxes	**$18,923**	$(8,852)	(314)	**$28,727**	$(684)	(4,300)
Depletion, depreciation and amortization	**45,691**	38,943	17	**132,750**	106,883	24
Stock-based compensation	**2,998**	1,052	185	**5,973**	3,223	85
Gain on disposition of property, plant and equipment	**–**	–	–	**(6)**	–	–
Transaction costs	**–**	–	–	**–**	5,663	(100)
Accretion expense on decommissioning obligations	**1,041**	892	17	**3,063**	2,706	13
Unrealized loss (gain) on financial instruments	**(74)**	2,739	(103)	**17,622**	(16,991)	(204)
Adjusted operating field netback	**$68,579**	$34,774	97	**$188,129**	$100,800	87
Per share - basic	**$0.30**	$0.15	100	**$0.83**	$0.45	84
Per share - diluted	**$0.29**	$0.15	93	**$0.81**	$0.45	80
Net income (loss)	**$13,004**	$(6,742)	(293)	**$19,358**	$(1,399)	(1,484)
Per share - basic	**$0.06**	$(0.03)	(300)	**$0.08**	$(0.01)	(900)
Per share - diluted	**$0.06**	$(0.03)	(300)	**$0.08**	$(0.01)	(900)

Third quarter and the first nine months of 2018 adjusted operating field netback (see "Non-IFRS Measures") was higher on an absolute basis than the same periods in 2017, primarily due to increased production, crude oil prices and operating netbacks. The increase in operating 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 $13.0 million ($0.06 per share basic and diluted) and $19.4 million ($0.08 per share basic and diluted) during the three and nine months ended September 30, 2018, respectively, compared to a net loss of $6.7 million ($0.03 per share basic and diluted) and $1.4 million ($0.01 per share basic and diluted) for the same periods in 2017.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

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

	Three months ended September 30,			Nine months ended September 30,		
($ thousands)	**2018**	2017	% change	**2018**	2017	% change
Land	**$1,337**	$610	119	**$4,648**	$1,882	147
Geological and geophysical	**–**	–	–	**13**	2,022	(99)
Drilling and completion	**61,928**	58,105	7	**151,962**	117,424	29
Equipment and facilities	**14,127**	14,643	(4)	**41,590**	33,175	25
Capitalized G&A	**690**	661	4	**2,070**	1,983	4
Office equipment	**67**	44	52	**170**	300	(43)
Total capital expenditures	**$78,149**	$74,063	6	**$200,453**	$156,786	28

Building on the momentum from a short spring break up in the second quarter, Tamarack successfully executed its summer 2018 capital program through the third quarter. Tamarack has invested a total of $200.5 million ($198.2 million including acquisitions, net of dispositions) as of September 30, 2018. During the third quarter of 2018, the Company drilled, completed and equipped 25 (24.6 net) Viking oil wells, three (1.8 net) Cardium oil wells, two (2.0 net) Penny oil wells and four (4.0 net) Redwater wells plus one vertical stratigraphic exploratory well. In addition to the third quarter drilling program, the Company also completed and brought on production wells that were drilled in late Q2/18 including 18 (17.8 net) Viking oil wells, six (6.0 net) Cardium oil wells, and one (1.0 net) Penny oil. The Company also drilled 18 (17.8 net) Viking oil wells and one (1.0 net) Penny oil well and that will be brought on production in the fourth quarter of 2018, resulting in total drilling for the quarter of 43 (42.4 net) Viking oil wells, three (1.8 net) Cardium oil wells, three (3.0 net) Penny oil wells and four (4.0 net) Redwater oil wells plus one vertical stratigraphic exploratory well.

Tamarack also dedicated capital to the continued development of a waterflood program in Veteran, AB. Of the 43 Viking oil wells drilled in the quarter, nine wells were drilled as future injection wells, which will produce to recover capital costs until the commencement of the injection project in the first half of 2019. Additionally, significant investment in the pipeline and facility infrastructure required to operate the infield water-flood was initiated and will continue through the end of 2018 and into early 2019. The water-flood project is designed to improve oil recoveries, reduce corporate decline rates and increase production rates while utilizing existing owned infrastructure. These supplementary projects are subject to the same rate of return thresholds as those used for development drilling when competing for capital.

Thus far in 2018, Tamarack has demonstrated exceptional operational efficiency. This has led the Company to accelerate capital for the last two quarters in order to benefit from the economies of scale offered by executing a larger program. As previously announced, Tamarack plans to accelerate approximately $28 million of its first quarter 2019 drilling program into the fourth quarter as the Company is ahead of its original drilling schedule. The Company is on track to spend $230 to $235 million in 2018, which is in line with the originally planned $195 to $205 million capital budget in addition to the $28 million of accelerated capital.

	September 30, 2018 Wells Drilled Summary		2017 Wells Drilled Summary	
	Gross	Net	Gross	Net
Heavy Oil	0.0	0.0	5.0	5.0
Viking	106.0	102.5	104.0	99.0
Mannville	0.0	0.0	3.0	3.0
Cardium	19.0	17.8	16.0	15.3
Other	14.0	13.7	5.0	4.1
	139.0	134.0	133.0	126.4

The Company's net undeveloped land totaled 422,405 acres as at September 30, 2018.

Property Acquisitions and Dispositions

There were no acquisitions or dispositions during the third quarter of 2018.

Liquidity and Capital Resources

($ thousand)	**September 30, 2018**	September 30, 2017	June 30, 2018
Working capital deficiency	**$23,214**	$32,753	$24,376
Bank debt	**168,970**	162,164	156,965
Net debt	**$192,184**	$194,917	$181,341
Quarterly adjusted operating field netback	**$68,579**	$34,774	$61,005
Annualized factor	**4**	4	4
Annualized adjusted operating field netback	**274,316**	139,096	244,020
Net debt to annualized adjusted operating field netback	**0.7x**	1.4x	0.7x

Tamarack's net debt (see "Non-IFRS Measures"), including working capital deficiency but excluding the fair value of financial instruments, totaled $192.2 million as at September 30, 2018. This compares to the previous quarter and the third quarter of 2017, in which net debt of $181.3 million and $194.9 million was recorded, respectively. Tamarack's third quarter 2018 net debt to annualized adjusted operating field netback ratio was 0.7 times.

The $78.1 million of capital expenditures and property acquisitions, net of dispositions, invested during the third quarter of 2018 was funded partially by Tamarack's adjusted operating field netback ($68.6 million) and the remainder by an increase in net debt and stock option proceeds ($9.6 million).

With continued commodity price volatility and most recently price differential volatility impacting the Canadian 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 realized 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, thereby reducing the total number of shares outstanding. 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 September 30, 2018, the Company spent $9,413,000 to purchase and cancel 2,090,200 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 September 30, 2018, Tamarack had 227,604,165 common shares, 445,516 common shares held in treasury, 3,095,833 options and 7,493,809 RSUs outstanding. At November 7, 2018, there were 227,641,265 common shares, 445,516 common shares held in treasury, 2,944,833 options and 7,493,809 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 September 30, 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 September 30, 2018 and are exchangeable into common shares of Tamarack at an exchange price of $3.12 per common share.

As noted under 'Liquidity and Capital Resources' above, during the nine months ended September 30, 2018, Tamarack purchased and cancelled 2,090,200 outstanding common shares under the NCIB, for a total investment of $9,413,000. The NCIB provides management with an instrument that can be employed when there is a perceived misalignment between the Company's prevailing share price and the underlying current and future potential value of its assets. In addition to supporting the Company's commitment to generating per share value, the NCIB also helps to offset the potential for dilutive impact that may be associated with the exercise and settlement of options issued under Tamarack's stock-based compensation program.

Over and above the NCIB, during the nine months ended September 30, 2018, the Company also directed $4,000,000 to the purchase of 970,000 outstanding common shares in the open market. Once purchased, these shares are held in trust by Tamarack's trustee and used to settle RSUs upon future exercise. This practice mitigates dilution by eliminating the need to issue new shares from treasury for the settlement of RSUs. Instead, Tamarack has the ability, when needed, to 'draw down' from the remaining balance of purchased shares that are held in trust to settle RSU exercises, further supporting Tamarack's per share metrics. At September 30, 2018, the balance of the remaining common shares held in trust totaled 445,516.

Bank Debt

Tamarack currently has available a revolving credit facility in the amount of $260 million and a $30 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 24, 2019. If not extended on May 24, 2019, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that date.

Subsequent to the quarter and during the semi-annual review of facilities, an accordion feature was added to the lending agreement which allows Tamarack to increase the revolving credit facility to $370 million for a total Facility of $400 million, upon exercise and syndicate approval. The accordion feature bears no fees, including standby, until exercised.

The total interest rate on the Facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio as defined in the Facility. The interest rate will vary depending on the lending vehicle employed and the Company's current net debt-to-cash-flow ratio. Interest on bankers' acceptances ("BA") and LIBOR Based Loans ("LIBOR") will vary based on a BA/LIBOR pricing grid from a low of the banks' posted rates plus 1.5% to a high of the banks' posted rates plus 3.5%. Interest on prime lending varies based on a prime rate pricing grid from a low of the banks' prime rates plus 0.5% to a high of the banks' prime rates plus 2.5%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.3375% to a high of 0.7875% 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. As at September 30, 2018, the Facility was secured by a $550 million supplemental debenture with a floating charge over all assets. Subsequent to the end of the quarter, the security was increased to $1 billion supplemental debenture to align with the increase in the borrowing base with the addition of the accordion feature. 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 September 30, 2018, the Company is in compliance with all covenants.

Guidance

Tamarack's third quarter production averaged 24,765 boe/d, which was just above the previously released 24,700 boe/d production estimate for the period. Production for the quarter was above the upper end of its average annual production range of 24,000 to 24,500 boe/d with an oil and NGL weighting of 66% at the upper end of the range relative to the expected weighting of 64 to 66%. Average annual production for 2018 remains on target to meet previous guidance of 24,000 to 24,500 boe/d (64 to 66% oil and NGLs) with fourth quarter exit production guidance unchanged at 24,500 to 25,000 boe/d (65 to 67% liquids).

Tamarack's 2018 capital budget remains unchanged from previous guidance at $223 to $233 million (including $28.4 million of capital accelerated from 2019 into 2018). Through the first the nine months of 2018, the Company has clearly demonstrated the strength of its strategy and the value in focusing on drilling opportunities that offer a pay back in 1.5 years or less. Tamarack has continued to outperform through the third quarter, driven by strong drilling results, higher than expected production volumes, lower operating costs and stronger oil prices. For the balance of 2018, Tamarack anticipates spending approximately $30-35 million of its remaining capital budget to complete the 18 Viking wells drilled late in Q3/18, continue installation of the pipeline to handle water injection for the Veteran waterflood in early 2019 and to drill 16 Viking wells in Veteran that are expected to be completed in Q1/19. Approximately half of the $28 million of accelerated capital will be directed to the Veteran waterflood projects, with the other half directed to initiate the Company's Q1/19 drilling program in Q4/18, which includes de-risking lands to the west, east and south of Veteran that were originally targeted for delineation in early 2019. Several of these wells will validate the extension of the resource base in three directions from the existing Veteran Unit potentially adding years of production growth both with primary and waterflood recovery.

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

	2018 Guidance
Average annual production (boe/d)	24,000 - 24,500
Liquids weighting (%)	~64 - 66
Exit production (boe/d)	24,500 - 25,000
Liquids weighting (%)	~65 - 67
2018 Capital expenditure range ($millions)	$223 to $233[3]
2019 capital expenditures accelerated into 2018 ($million)	$28
Year end 2018 net debt[1] to Q4 annualized adjusted operating field netback[2] ratio *(including hedges)*	<1.0 times[4]
Liquidity on existing credit facilities ($millions)	~$100
Original 2018 budget price assumptions:	
WTI ($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"

(3) Includes 2019 acceleration of ~$28 million

(4) Ratio dependent on commodity prices for Q4/18 reflecting the Edmonton Par price shown in the assumptions above.

Since the end of Q3/18, the WTI/Edmonton Par light oil differential severely widened due to ongoing market oversupply and Canadian infrastructure restrictions. Recently, continued pricing pressures led to differentials reaching unprecedented levels that have exceeded US$30/bbl, driving further underperformance of the Edmonton Par price relative to WTI. While the duration and magnitude of these extreme price conditions are difficult to predict, Tamarack is committed to conservatively planning around future oil prices and continues to explore ways to mitigate and manage market risk. As a result of the Company's ongoing commitment to maintaining a strong balance sheet with significant financial flexibility, Tamarack is well positioned to endure oil price and differential volatility. However, should the current pricing environment continue through the balance of 2018 and into first quarter 2019, adjusted operating field netbacks will be negatively impacted.

Tamarack has historically demonstrated prudence in capital allocation decisions during volatile commodity price environments and will continue to closely monitor current and future commodity prices and price differentials. The Company's 2019 preliminary $250 million capital expenditure budget contemplated spending approximately 95% of its anticipated adjusted operating field netback assuming commodities average US$60/bbl WTI, $68.50/bbl Edmonton Par price, $1.65/GJ AECO and a $0.78 Canadian dollar. Given the current lack of visibility on timing for differentials to improve, Tamarack anticipates formalizing its 2019 capital expenditure budget in early 2019 and in order to preserve value, may elect to defer some Q1/19 projects, including bringing new production on-stream, until the current wide differentials have abated.

The Company's preliminary 2019 budget is summarized in the following table:

	2019 Preliminary Budget
Average annual production (boe/d)	25,500 - 26,500
Liquids weighting (%)	~65 - 67
Exit production (boe/d)	27,500 - 28,000
Liquids weighting (%)	~66 – 68
2019 Capital expenditures accelerated into 2018 ($millions)	$28
2019 Capital expenditures ($millions)	$222
2019 price assumptions:	
WTI ($US/bbl)	$60.00
Edmonton Par ($CDN/bbl)	$68.50
AECO ($CDN/GJ)	$1.65
Canadian/US dollar exchange rate	$0.78

Should forecasted realized commodity prices significantly fluctuate from levels outlined in the assumptions above, Tamarack maintains control to 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 September 30, 2018:

($ thousands)	2018	2019	2020	2021	2022	2023	2024+
Bank debt	–	-	168,970	–	–	–	–
Office lease	136	542	263	–	–	–	–
Take or pay commitments(1)	219	2,205	2,256	2,294	2,340	2,396	–
Rental fee(2)	1,578	6,312	6,312	6,312	4,441	2,570	2,427
Gas transportation(3)	612	730	229	76	–	–	–
Total	2,545	9,789	178,030	8,682	6,781	4,966	2,427

(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 3 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, rental fee of $0.05 million per month for a maximum period of 96 months starting in January 2018 relating to one facility and rental fee of $0.05 million per month for a maximum period of 96 months starting in April 2018 relating to one facility.

(3) 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”, “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 a key measure to demonstrate the Company’s ability to generate funds to repay debt and fund future capital investment. The Company uses net debt (bank debt plus working capital deficiency, excluding the fair value of financial instruments) as an alternative measure of outstanding debt. The Company considers operating netback a key measure as it demonstrates corporate profitability relative to current commodity prices. Netbacks, which have no IFRS equivalent, are calculated on a per boe basis by deducting royalties and net production and transportation costs from petroleum and natural gas sales, including realized gains and losses on commodity and foreign exchange 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 certain non-cash items including: stock-based compensation; accretion expense on decommissioning obligations; depletion, depreciation and amortization; 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 starting 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)	September 30, 2018	December 31, 2017
Accounts payable and accrued liabilities	$69,497	$51,059
Accounts receivable	(42,071)	(38,673)
Prepaid expenses and deposits	(4,212)	(3,095)
Working capital deficiency	23,214	9,291
Bank debt	168,970	163,889
Net debt	$192,184	$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	**Sep. 30, 2018**	Jun. 30, 2018	Mar. 31, 2018	Dec. 31, 2017	Sep. 30, 2017	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016
Sales volumes								
Natural gas *(mcf/d)*	**49,943**	52,376	51,879	51,956	49,987	47,696	45,852	31,226
Oil and NGL *(bbls/d)*	**16,441**	15,124	14,885	14,148	12,210	11,387	10,154	6,249
Average boe/d *(6:1)*	**24,765**	23,853	23,532	22,807	20,541	19,336	17,796	11,453
Product prices								
Natural gas *($/mcf)*	**1.63**	1.65	2.25	1.89	1.62	3.01	2.89	3.27
Oil and NGL *($/bbl)*	**73.81**	72.66	65.86	62.34	50.29	51.77	55.74	52.88
Oil equivalent *($/boe)*	**52.29**	49.69	46.62	42.97	33.83	37.91	39.25	37.76
(000s, except per share amounts)								
Financial results								
Gross revenues	**119,134**	107,859	98,736	90,160	63,927	66,715	62,870	39,793
Cash provided by operating activities	**62,644**	64,606	60,285	50,056	35,237	34,537	24,695	17,609
Adjusted operating field netback [(1)]	**68,579**	61,005	58,545	57,583	34,774	33,670	32,356	20,453
Per share – basic	**0.30**	0.27	0.26	0.25	0.15	0.15	0.15	0.15
Per share – diluted	**0.29**	0.26	0.25	0.25	0.15	0.15	0.15	0.15
Net income (loss)	**13,004**	3,060	3,294	(12,525)	(6,742)	3,053	2,290	(8,425)
Per share – basic	**0.06**	0.01	0.01	(0.05)	(0.03)	0.01	0.01	(0.06)
Per share – diluted	**0.06**	0.01	0.01	(0.05)	(0.03)	0.01	0.01	(0.06)
Capital expenditures	**78,149**	52,674	69,630	35,516	74,063	19,002	63,721	14,863
Net acquisitions (dispositions)	**–**	(5,009)	2,790	1,713	2,962	1,301	75,995	(2,446)
Total assets	**1,291,058**	1,237,571	1,240,335	1,207,809	1,206,886	1,178,404	1,186,285	663,564
Net debt [(1)]	**192,184**	181,341	186,732	173,180	194,917	152,354	165,561	52,316
Bank debt	**168,970**	156,965	165,750	163,889	162,164	140,795	135,484	45,227
Decommissioning obligations	**192,409**	185,038	182,216	177,793	167,102	171,909	164,012	112,115

(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, adjusted operating field netbacks 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 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.
- The Company recorded $5.7 million in transaction costs in the first quarter of 2017 related to the Viking Acquisition.
- 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.

(b) **Exploration and evaluation assets –** The costs of drilling exploratory wells are initially capitalized as 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 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) **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.

(f) **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 has developed a plan to identify and review its various lease agreements in order to determine the impact that adoption of IFRS 16 will have on the consolidated financial statements. The Company is completing its review and analysis of the significant lease contracts that fall into the scope of the new standard and continues to work through scoping and completeness procedures in preparation for adoption on January 1, 2019.

Changes in Accounting Policies

Adoption of IFRS 15, "Revenue 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.

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 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

September 30, 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, size, terms, use and renewal of the Facility;
- estimated production rates in 2018, including in respect of the Cardium, Viking and Penny oil wells;
- the performance of the Viking waterflood project, including oil recoveries and corporate decline rates;
- future net production and transportation expenses and operating costs;
- Tamarack's focus on preserving balance sheet strength by adjusting capital spending relative to commodity prices;
- Tamarack's intent to maintain balance sheet flexibility to allow the Company to take advantage of opportunities within the core areas;
- Tamarack's primary focus areas for production growth;
- future drilling plans;
- the timing of the Viking Pipeline Project;
- the impact of the Viking Pipeline Project on operating costs, transportation and the development of the Veteran Viking oil play;
- 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;

- deferred tax liabilities;
- expectations as to royalty rates as a percentage of revenue;
- future capital expenditures and capital program funding;
- future investment in pipeline infrastructure;
- contractual obligations and commitments;
- estimated year end net debt to annualized adjusted operating field netback ratio;
- the estimates used to calculate the decommissioning obligations and depletion of PP&E;
- the Company's capital budget program and guidance for 2018 and 2019;
- share buy-backs for cancellation under the NCIB and RSU settlements;
- Tamarack's expectation that the shut-in gas production will not affect its original 2018 production forecast;
- Tamarack's use of financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates;
- Tamarack's ability to explore alternative gas markets and diversify its gas price exposure;
- Tamarack's plan to accelerate or reduce capital expenditures, redirect capital to purchase shares or pay down debt if commodity prices significantly fluctuate from the 2018 price assumptions;
- the capital acceleration and impact on 2018 and 2019 volumes;
- allocating incremental capital to drill injector wells at Veteran for the water-flood project and the expected benefits of this project and timing thereof;
- the preliminary 2019 budget;
- 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, price differentials and the actual prices received for the Company's products;
- expected net production and transportation expenses and operating costs;
- 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 and the Viking Acquisition and the related drilling programs;
- 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", "Changes in Accounting Policies", "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 and Dispositions", "Liquidity and Capital Resources", "Share Capital", "Bank Debt", "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, operating netback, net debt to annualized adjusted operating field netback ratio, capital cost payout, 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)

	September 30, 2018	December 31, 2017
Assets		
Current assets:		
Accounts receivable	$42,071	$38,673
Prepaid expenses and deposits	4,212	3,095
Fair value of financial instruments (note 4)	628	1,941
	46,911	43,709
Fair value of financial instruments (note 4)	145	–
Property, plant and equipment (note 6)	1,240,886	1,162,272
Exploration and evaluation assets (note 7)	3,116	1,828
	$1,291,058	$1,207,809
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$69,497	$51,059
Fair value of financial instruments (note 4)	23,047	7,936
	92,544	58,995
Bank debt (note 12)	168,970	163,889
Fair value of financial instruments (note 4)	2,825	1,482
Decommissioning obligations (note 8)	192,409	177,793
Deferred tax liability	41,164	31,795
Shareholders' equity:		
Share capital (note 10)	850,967	850,357
Treasury shares (note 10)	(1,838)	–
Contributed surplus	29,781	27,180
Deficit	(85,764)	(103,682)
	793,146	773,855
Subsequent events (note 4 and 12)		
Commitments (note 14)		
	$1,291,058	$1,207,809

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Income (Loss) and Comprehensive Income (Loss)
For the three and nine months ended September 30, 2018 and 2017
(unaudited)(thousands, except per share amounts)

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Revenue:				
Oil and natural gas (note 5)	$119,134	$63,927	$325,729	$193,512
Processing income (note 5)	170	556	232	696
Royalties	(12,075)	(7,043)	(33,999)	(20,670)
Realized gain (loss) on financial instruments (note 4)	(9,479)	3,994	(18,027)	2,422
Unrealized gain (loss) on financial instruments (note 4)	74	(2,739)	(17,622)	16,991
	97,824	58,695	256,313	192,951
Expenses:				
Production	23,813	21,827	69,392	61,117
General and administration	3,295	3,057	10,048	9,047
Transaction costs	–	–	–	5,663
Stock-based compensation (note 13)	2,998	1,052	5,973	3,223
Finance	3,104	2,668	9,429	7,702
Depletion, depreciation and amortization (note 6 and 7)	45,691	38,943	132,750	106,883
Gain on disposition of property, plant and equipment	–	–	(6)	–
	78,901	67,547	227,586	193,635
Income (loss) before taxes	18,923	(8,852)	28,727	(684)
Deferred income tax recovery (expense)	(5,919)	2,110	(9,369)	(715)
Net income (loss) and comprehensive income (loss)	$13,004	$(6,742)	$19,358	$(1,399)
Net income (loss) per share (note 11):				
Basic	$ 0.06	$(0.03)	$ 0.08	$(0.01)
Diluted	$ 0.06	$(0.03)	$ 0.08	$(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 net of treasury shares	Share capital	Treasury shares	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	1,629	4,914	–	–	–	4,914
Purchase of common shares for cancellation	(2,090)	(8,002)	–	29	(1,440)	(9,413)
Purchase of common shares for RSU exercise	(970)	–	(3,999)	–	–	(3,999)
RSU exercise	524	–	2,161	(2,161)	–	–
Transfer on exercise of stock options and RSU's	–	3,698	–	(3,698)	–	–
Stock-based compensation	–	–	–	8,431	–	8,431
Net income	–	–	–	–	19,358	19,358
Balance at September 30, 2018	227,603	$850,967	$(1,838)	$29,781	$(85,764)	$793,146

	Number of common shares	Share capital	Treasury shares	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	90,166	310,092	–	–	–	310,092
Share issue costs, net of tax of $5.5	–	(15)	–	–	–	(15)
Transfer on exercise of stock options	–	71	–	(71)	–	–
Stock-based compensation	–	–	–	4,740	–	4,740
Net loss	–	–	–	–	(1,399)	(1,399)
Balance at September 30, 2017	227,693	$847,702	$ –	$26,611	$(91,157)	$783,156

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three and nine months ended September 30, 2018 and 2017
(unaudited)(thousands)

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	2018	2017
Cash provided by (used in):				
Operating:				
Net income (loss)	$13,004	$(6,742)	$19,358	$(1,399)
Items not involving cash:				
Depletion, depreciation and amortization (note 6 and 7)	45,691	38,943	132,750	106,883
Stock-based compensation (note 13)	2,998	1,052	5,973	3,223
Gain on disposition of property, plant and equipment	–	–	(6)	–
Accretion expense on decommissioning obligations (note 8)	1,041	892	3,063	2,706
Unrealized loss (gain) on financial instruments (note 4)	(74)	2,739	17,622	(16,991)
Deferred income tax expense (recovery)	5,919	(2,110)	9,369	715
Abandonment expenditures (note 8)	(312)	(314)	(401)	(675)
Changes in non-cash working capital (note 9)	(5,623)	777	(193)	7
Cash provided by operating activities	62,644	35,237	187,535	94,469
Financing:				
Change in bank debt (note 12)	12,005	21,371	5,081	116,939
Proceeds from exercise of options (note 10)	4,031	–	4,914	–
Purchase of common shares for cancellation (note 10)	(4,992)	–	(9,413)	–
Purchase of common shares for RSU exercises (note 10)	–	–	(3,999)	–
Share issue costs	–	–	–	(21)
Cash provided by (used in) financing activities	11,044	21,371	(3,417)	116,918
Investing:				
Property, plant and equipment additions (note 6)	(77,055)	(70,828)	(197,521)	(147,933)
Exploration and evaluation additions (note 7)	(1,094)	(3,235)	(2,932)	(8,853)
Acquisitions	–	(3,253)	(2,781)	(109,716)
Proceeds from disposal of property, plant and equipment (note 6)	–	291	5,000	291
Changes in non-cash working capital (note 9)	4,461	20,417	14,116	54,824
Cash used in investing activities	(73,688)	(56,608)	(184,118)	(211,387)
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:

Statement of compliance:

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

These condensed consolidated interim financial statements have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company for the year ended December 31, 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 November 7, 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.

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 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. Risk management contracts:

It is the Company's policy to economically hedge some oil and natural gas sales and foreign exchange 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 September 30, 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	7,100 bbls/day	October 1, 2018 – December 31, 2018	WTI fixed price	US $59.91	$(10,961)
Crude oil	4,000 bbls/day	January 1, 2019 – March 31, 2019	WTI fixed price	US $63.28	$(4,212)
Crude oil	3,500 bbls/day	April 1, 2019 – June 30, 2019	WTI fixed price	US $65.28	$(2,600)
Crude oil	2,700 bbls/day	July 1, 2019 – September 30, 2019	WTI fixed price	US $64.41	$(1,964)
Crude oil	2,100 bbls/day	October 1, 2019 – December 31, 2019	WTI fixed price	US $63.17	$(1,553)
Crude oil	500 bbls/day	January 1, 2020 – March 31, 2020	WTI fixed price	US $65.45	$(169)
Crude oil	500 bbls/day	January 1, 2019 – December 31, 2019	WTI written call option	US $52.00	$(4,413)
Foreign exchange	9,000,000 US$/mth	October 1, 2018 – December 31, 2018	Exchange rate	Cdn $1.2937	$97
Foreign exchange	6,000,000 US$/mth	January 1, 2019 – March 31, 2019	Exchange rate	Cdn $1.3013	$236
Foreign exchange	4,000,000 US$/mth	April 1, 2019 – June 30, 2019	Exchange rate	Cdn $1.2955	$111
Foreign exchange	4,000,000 US$/mth	July 1, 2019 – September 30, 2019	Exchange rate	Cdn $1.2995	$184
Foreign exchange	3,000,000 US$/mth	October 1, 2019 – December 31, 2019	Exchange rate	Cdn $1.2985	$145
					$(25,099)

At September 30, 2018, the commodity and foreign exchange contracts were fair valued with a liability of $25,099 (December 31, 2017 - $7,477 liability) recorded on the balance sheet and an unrealized loss of $17,622 recorded in earnings for the nine months ended September 30, 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 September 30, 2018, the Company held the following physical commodity contracts.

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	5,000 mmbtu/day	October 1, 2018 – October 31, 2018	AECO/Henry Hub differential	Index – US $1.88
Natural gas	10,000 mmbtu/day	November 1, 2018 – March 31, 2019	AECO/Henry Hub differential	Index – US $1.43
Natural gas	2,500 mmbtu/day	January 1, 2019 – March 31, 2019	AECO/Henry Hub differential	Index – US $1.42
Natural gas	10,000 mmbtu/day	April 1, 2019 – October 31, 2019	AECO/Henry Hub differential	Index – US $1.60
Natural gas	2,500 mmbtu/day	November 1, 2019 – March 31, 2020	AECO/Henry Hub differential	Index – US $1.33
Crude oil	1,500 bbls/day	October 1, 2018 – December 31, 2018	WTI/Edm Differential	US $5.50

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)	**September 30, 2018**	December 31, 2017
Risk management contracts		
Current asset	**$628**	$1,941
Long-term asset	**145**	–
Current liability	**(23,047)**	(7,936)
Long-term liability	**(2,825)**	(1,482)
Balance, end of the period	**$(25,099)**	$(7,477)

Since September 30, 2018, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	200 bbls/day	January 1, 2020 – March 31, 2020	WTI fixed price	US $70.75
Foreign exchange	2,000,000 US$/mth	April 1, 2019 – June 30, 2019	Exchange rate	Cdn $1.3045
Foreign exchange	1,000,000 US$/mth	July 1, 2019 – September 30, 2019	Exchange rate	Cdn $1.3017

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.

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

The Company's revenues were primarily generated in its core areas: the Cardium oil play in the Wilson Creek/Alder Flats areas of central Alberta; the Viking oil play in central and southern Alberta and west central Saskatchewan; 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 volumes to numerous oil and natural gas marketers under customary industry sale and payment terms. As at September 30, 2018, revenue was earned from customers, of which four customers account for $34.8 million of the accounts receivable at September 30, 2018.

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2018**	2017	**2018**	2017
Light oil	**$102,098**	$49,682	**$274,610**	$142,398
Heavy oil	**3,906**	2,568	**8,487**	6,320
Natural gas	**7,498**	7,434	**25,865**	32,428
Natural gas liquids	**5,632**	4,243	**16,767**	12,366
Oil and natural gas revenue	**$119,134**	$63,927	**$325,729**	$193,512
Processing income	**170**	556	**232**	696
Total revenue	**$119,304**	$64,483	**$325,961**	$194,208

Refer to note 4 for a listing of physical delivery contracts as at September 30, 2018.

Included in accounts receivable at September 30, 2018 was $38.0 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 September 30, 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	2,781	–	2,781
Cash additions	197,351	170	197,521
Decommissioning costs	12,088	–	12,088
Stock-based compensation	2,458	–	2,458
Transfer from exploration and evaluation assets (note 7)	894	–	894
Disposals	(5,128)	–	(5,128)
Balance at September 30, 2018	$1,834,994	$1,538	$1,836,532
Accumulated 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	131,825	175	132,000
Balance at September 30, 2018	$594,794	$852	$595,646

	Oil and natural gas interests	Other assets	Total
Carrying amounts:			
At December 31, 2017	$1,161,581	$691	$1,162,272
At September 30, 2018	$1,240,200	$686	$1,240,886

During the nine months ended September 30, 2018, the Company disposed of its interest in certain oil and gas infrastructure for total proceeds of $5,000. The calculation of depletion at September 30, 2018 includes estimated future development costs of $631,764 (December 31, 2017 – $694,759) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $56,604 (December 31, 2017 – $44,825).

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	2,932
Transfer to property, plant and equipment (note 6)	(894)
Balance at September 30, 2018	$26,006
Accumulated amortization and impairment:	
Balance at January 1, 2017	$21,353
Amortization	787
Balance at December 31, 2017	22,140
Amortization	750
Balance at September 30, 2018	$22,890

	Total
Carrying amounts:	
At December 31, 2017	$1,828
At September 30, 2018	$3,116

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 $189.9 million at September 30, 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 September 30, 2018 as presented in the table below:

($ thousands)	**Nine months ended September 30, 2018**	Year ended December 31, 2017
Balance, beginning of the period	**$177,793**	$112,115
Liabilities incurred	**12,088**	12,689
Liabilities acquired	**–**	19,207
Change in estimates	**–**	1,815
Change in discount rate on acquisition	**–**	29,201
Expenditures	**(401)**	(898)
Liabilities disposed	**(134)**	(77)
Accretion	**3,063**	3,741
Balance, end of the period	**$192,409**	$177,793

9. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2018**	2017	**2018**	2017
Source/(use) of cash:				
Accounts receivable	**$(11,658)**	$237	**$(3,398)**	$(10,219)
Prepaid expenses and deposits	**(779)**	1,727	**(1,117)**	1,124
Accounts payable and accrued liabilities	**11,275**	19,230	**18,438**	34,759
Working capital acquired	**–**	–	**–**	29,167
	$(1,162)	$21,194	**$13,923**	$54,831
Related to operating activities	**$(5,623)**	$777	**$(193)**	$7
Related to investing activities	**$4,461**	$20,417	**$14,116**	$54,824

The following are included in cash flows from operating activities:

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2018**	2017	**2018**	2017
Interest paid in cash	**$2,063**	$1,776	**$6,366**	$4,996

10. Shareholders' equity:

a) Share capital:

At September 30, 2018 the Company was authorized to issue an unlimited number of common shares and preferred shares without nominal or par value.

During the nine months ended September 30, 2018, 1,531,167 stock options at an average price of $3.21 per share were exercised for gross proceeds of $4.9 million. There were also 98,000 restricted share awards converted to common shares.

b) Normal course issuer bid:

On April 4, 2018, the Company announced that the Toronto Stock Exchange had accepted the Company's intention to commence a normal course issuer bid ("NCIB"). Pursuant to the NCIB, the Company is permitted to purchase up to 8.6 million common shares of the Company between April 6, 2018 and April 5, 2019. During the nine months ended September 30, 2018, the Company repurchased 2,090,200 common shares at an average price of $4.50 per common share, for a total repurchase cost of $9.4 million.

c) Treasury shares:

During the nine months ended September 30, 2018, the Company spent $4.0 million to purchase 970,000 common shares to be used to settle restricted stock units on the date of exercise. As at September 30, 2018, 446,000 common shares remain classified as treasury shares to be used for future settlements.

11. Income (loss) per share:

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands, except per share amounts)	**2018**	2017	**2018**	2017
Net income (loss)	**$13,004**	$(6,742)	**$19,358**	$(1,399)
Weighted average shares - basic	**227,031**	227,691	**227,891**	224,376
Weighted average shares - diluted	**233,203**	227,691	**233,215**	224,376
Net income (loss) per share-basic	**$ 0.06**	$(0.03)	**$ 0.08**	$(0.01)
Net income (loss) per share-diluted	**$ 0.06**	$(0.03)	**$ 0.08**	$(0.01)

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three and nine months ended September 30, 2018, 11.3 million and 10.6 million, respectively, stock options, preferred shares and restricted stock units were included in the diluted weighted average number of shares outstanding. For the three and nine months ended September 30, 2017, 9.9 million stock options, preferred shares and restricted stock units were excluded in the diluted weighted average numbers of shares outstanding as they were anti-dilutive.

12. Bank debt:

The Company currently has available a revolving credit facility in the amount of $260 million and a $30 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 24, 2019. If not extended on May 24, 2019, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that date.

Subsequent to the quarter and during the semi-annual review of facilities, an accordion feature was added to the lending agreement which allows Tamarack to increase the revolving credit facility to $370 million for a total Facility of $400 million, upon exercise and syndicate approval. The accordion feature bears no fees, including standby, until exercised.

The total interest rate on the Facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio as defined in the Facility. The interest rate will vary depending on the lending vehicle employed and the Company's current net debt-to-cash-flow ratio. Interest on bankers' acceptances ("BA") and LIBOR Based Loans ("LIBOR") will vary based on a BA/LIBOR pricing grid from a low of the banks' posted rates plus 1.5% to a high of the banks' posted rates plus 3.5%. Interest on prime lending varies based on a prime rate pricing grid from a low of the banks' prime rates plus 0.5% to a high of the banks' prime rates plus 2.5%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.3375% to a high of 0.7875% 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. As at September 30, 2018, the Facility was secured by a $550 million supplemental debenture with a floating charge over all assets. Subsequent to the quarter, the security was increased to $1 billion supplemental debenture to align with the increase in borrowing base with the addition of the accordion feature. 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. As previously mentioned, a successful review was completed early in the fourth quarter of 2018. The next review is scheduled for May 2019.

At September 30, 2018, the Company had utilized the Facility in the amount of $169.0 million. The interest rate applicable to the drawn amounts as of this date was 3.9%. As at September 30, 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 September 30, 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 September 30, 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 shareholders 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 shares over the exercise price. For the nine months ended September 30, 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 16.0 million options or restricted share units to its employees, directors and consultants of which 10.6 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 nine months ended September 30, 2018.

The fair value of each option granted during the nine months ended September 30, 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	(1,531)	3.21
Forfeited	(124)	5.68
Outstanding, September 30, 2018	**3,096**	**$ 3.93**

The range of exercise prices of stock options outstanding and exercisable at September 30, 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	902	$2.71	2.8	470	$2.73
$ 3.01 – 5.00	1,795	$3.89	2.0	1,132	$4.16
$ 5.01 – 6.82	399	$6.82	0.9	399	$6.82
$ 1.86 – 6.82	**3,096**	**$3.93**	**2.1**	**2,001**	**$4.35**

(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 2.4 million restricted stock units granted during the nine months ended September 30, 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	2,378
Exercised	(622)
Forfeited	(80)
Outstanding, September 30, 2018	**7,494**
Exercisable, September 30, 2018	**1,183**

14. Commitments:

The following table summarizes the Company's commitments as at September 30, 2018:

($ thousands)	2018	2019	2020	2021	2022	2023	2024+
Office lease	136	542	263	–	–	–	–
Take or pay commitments(1)	219	2,205	2,256	2,294	2,340	2,396	–
Rental fee(2)	1,578	6,312	6,312	6,312	4,441	2,570	2,427
Gas transportation(3)	612	730	229	76	–	–	–
Total	2,545	9,789	9,060	8,682	6,781	4,966	2,427

(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 3 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, rental fee of $0.05 million per month for a maximum period of 96 months starting in January 2018 relating to one facility and rental fee of $0.05 million per month for a maximum period of 96 months starting in April 2018 relating to one facility.

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

CORPORATE INFORMATION

Directors

Floyd Price - Chairman(3)

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

Contact Information

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