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 years ended December 31, 2018 and 2017. This MD&A is dated and based on information available as at February 26, 2019 and should be read in conjunction with the audited consolidated financial statements and the notes thereto for the years ended December 31, 2018 and 2017. Additional information relating to Tamarack, including Tamarack's Annual Information Form, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). 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 20. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

Q4 and Year End 2018 Financial and Operating Highlights

- Maintained stable production volumes of 24,780 boe/d in the fourth quarter relative to 24,765 boe/d in the third quarter, while investing only $25.8 million in capital expenditures, a $52.3 million reduction from the previous quarter.
- Total adjusted operating field netbacks (previously referred to as "adjusted funds flow"; see "Non-IFRS Measures") increased 43% in 2018 to $226.5 million ($0.99 per share basic and $0.97 per share diluted), from $158.4 million in 2017 ($0.70 per share basic and diluted).
- In Q4/18, total adjusted operating field netback of $38.3 million exceeded capital spending of $21.0 million, net of acquisitions and dispositions, by $17.3 million resulting in excess total adjusted operating field netback for the period, which was directed to debt repayment and continued funding of the Company's active share repurchase program.
- Year over year, achieved a 20% increase in production, and an 8% increase in the oil and natural gas liquids ("NGL") weighting percentage, while spending $9 million less, after acquisitions and dispositions, than the Company's previous capital guidance mid-point.

- Full year 2018 net production and transportation expenses per boe were 6% lower relative to 2017, stemming primarily from increased production from the lower-cost Veteran area.
- Tamarack's continued increase in oil and liquids weighting through 2018 largely contributed to 16% higher operating netbacks (see "Non-IFRS Measures") compared to 2017, further supported by improved pricing and lower net production and transportation expenses per boe year over year.
- Invested $219.2 million in total capital expenditures, net of dispositions during 2018, which included drilling a total of 164 (158.2 net) wells, comprised of 129 (124.7 net) Viking oil wells, 19 (17.8 net) Cardium oil wells, four (4.0 net) Penny oil wells, 11 (10.7 net) Redwater oil wells, one exploratory vertical stratigraphic well and one (1.0 net) water source well. In addition to the fourth quarter drilling program, the Company also completed and brought on production wells that were drilled in Q3/18 including 18 (17.8 net) Viking oil wells and one (1.0 net) Penny oil well along with continued development of the Company's waterflood program.

Production

Quarter-over-Quarter

	Q4 2018	Q3 2018	% change
Production			
Light oil (bbls/d)	**14,163**	14,417	(2)
Heavy oil (bbls/d)	**755**	621	22
Natural gas liquids (bbls/d)	**1,485**	1,403	6
Natural gas (mcf/d)	**50,262**	49,943	1
Total (boe/d)	**24,780**	24,765	–
Percentage of oil and natural gas liquids	**66%**	66%	–

Average production for Q4/18 was consistent with the prior quarter. During the period, the Company added 1,237 boe/d from the Veteran development program (84% oil and NGL), 321 boe/d from the Penny development program (94% oil and NGL), 51 boe/d from the Redwater development program (98% oil and NGL) and 354 boe/d from Wilson Creek/Alder Flats program (69% oil and NGL). These gains were partially offset by expected declines from base production and 98 boe/d that was shut-in due to commodity prices.

In both the fourth and third quarters of 2018, the Company's oil and NGL weighting was 66%. In 2019, the Company expects its oil and NGL weighting to remain stable and average between 64% to 66%. Going forward, Tamarack's liquids weighting will ultimately depend on the timing of production additions from 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 December 31,			Years ended December 31,		
	2018	2017	% change	**2018**	2017	% change
Production						
Light oil (bbls/d)	**14,163**	12,189	16	**13,769**	9,929	39
Heavy oil (bbls/d)	**755**	500	51	**552**	511	8
Natural gas liquids (bbls/d)	**1,485**	1,459	2	**1,398**	1,547	(10)
Natural gas (mcf/d)	**50,262**	51,956	(3)	**51,108**	48,893	5
Total (boe/d)	**24,780**	22,807	9	**24,237**	20,136	20
Percentage of oil and natural gas liquids	**66%**	62%	6	**65%**	60%	8

Compared to the prior year, average production for the fourth quarter of 2018 increased by 9% while full year average production increased by 20%. These increases are attributable to the successful development drilling programs at Veteran, Wilson Creek, Penny and Redwater through 2018, partially offset by expected declines from base production.

Petroleum and Natural Gas Sales

Quarter-over-Quarter

	Q4 2018	Q3 2018	% change
Revenue ($ thousands)			
Oil and NGL	**$55,962**	$111,636	(50)
Natural gas	**17,113**	7,498	128
Total	**$73,075**	$119,134	(39)
Average realized price			
Light oil ($/bbl)	**36.78**	76.98	(52)
Heavy oil ($/bbl)	**49.33**	69.33	(29)
Natural gas liquids ($/bbl)	**33.72**	43.64	(23)
Combined average oil and NGL ($/boe)	**37.08**	73.81	(50)
Natural gas ($/mcf)	**3.70**	1.63	127
Revenue ($/boe)	**32.05**	52.29	(39)
Benchmark pricing:			
West Texas Intermediate (US$/bbl)	**58.79**	69.54	(15)
Edmonton Par (Cdn$/bbl)	**48.26**	77.26	(38)
Hardisty Heavy (Cdn$/bbl)	**34.23**	54.34	(37)
AECO daily index (Cdn$/mcf)	**1.55**	1.18	31
AECO monthly index (Cdn$/mcf)	**1.89**	1.35	40

Revenue from oil, natural gas and NGL sales was 39% lower in the fourth quarter of 2018 compared to the third quarter of 2018, entirely attributable to the sudden and extreme widening of price differentials for Canadian crude that occurred in the period. The abnormally wide differentials resulted in decreased wellhead pricing for crude oil and NGL, which was partially offset by higher natural gas pricing in the quarter.

WTI crude oil markets fell significantly in the fourth quarter of 2018, reaching a 2018 low with a spot price of US$42.68/bbl in the month of December. The average fourth quarter WTI price of US$58.79/bbl was 15% lower than the average third quarter price of US$69.54/bbl. In addition, the WTI/Edmonton Par light oil differential exploded in Q4/18 to reach a high of US$37.19/bbl and averaging US$29.30/bbl versus US$6.82/bbl in Q3/18. These factors compounded to decimate pricing for Canadian crude oil, including the light sweet market, causing the average Edmonton Par price to decrease 38% to $48.26/bbl versus the third quarter average of $77.26/bbl. Additionally, Tamarack's realized light oil wellhead price for the three months ended December 31, 2018 decreased 52% to $36.78/bbl from $76.98/bbl in the previous quarter. Due to continued issues related to market oversupply and Canadian infrastructure restrictions, the Government of Alberta announced production curtailments that took effect January 1, 2019. These curtailments, combined with active production management and engagement from the producer community, have resulted in a significant narrowing of the differential into the early part of 2019. Although this narrowing is a positive development, Tamarack believes the differential poses a significant risk to Canadian crude prices in 2019. Tamarack currently has approximately 30% of forecasted 2019 oil production protected with differential hedges. While the timing, duration and magnitude of extreme oil price conditions are difficult to predict, Tamarack is committed to conservatively planning and continues to explore ways to mitigate and manage market risk through financial and physical hedges.

The decrease in WTI prices through the quarter also impacted NGL prices, namely butane and condensate, as these contracts are priced relative to WTI, contributing to the lower average NGL price for the quarter. Realized NGL prices decreased 23% in Q4/18 to $33.72/bbl from $43.64/bbl in Q3/18. Similar to other products in the Alberta market, NGL supply currently outstrips demand. In particular, Alberta butane markets cratered significantly through the last six months of 2018. Given the majority of Tamarack's butane contracts are set as a percentage of WTI at the beginning of the contract year (April 1), to date the Company has not experienced material effects related to this weakness. If these market conditions persist, NGL prices could decrease significantly through the next contract year, which begins April 1, 2019.

Somewhat offsetting the oil and NGL price impacts during Q4/18, Tamarack's realized natural gas price increased significantly in the fourth quarter to $3.70/mcf compared to $1.63/mcf in Q3/18. To a lesser degree, the AECO daily benchmark price also increased quarter-over-quarter to $1.55/mcf from $1.18/mcf. These changes were due largely to higher winter season gas prices, with Tamarack's exposure to Eastern US gas markets specifically benefitting the Company's realized price.

Tamarack's exposure to various gas markets and pricing hubs is reflected below:

Natural Gas Market	**Percentage Exposure (as at December 31, 2018)**
AECO Daily (5A)	0.4
AECO Daily (5A) + premium (SK)	21.7
Dawn	8.9
Chicago	8.9
Michigan City Gate	8.9
Malin	17.7
Waddington	11.3
NYMEX (Physical Basis Swap)	22.2
	100%

Oversupply and takeaway capacity restrictions continue to create downward pricing pressure and volatility in Alberta natural gas markets. Despite increased usage across the colder winter months, AECO daily index pricing is expected to remain depressed through 2019 and beyond. Tamarack continues to benefit from multiple third-party gas sales contracts featuring time horizons for varying end dates up to 2022. These contracts provide diversification of the Company's natural gas price exposure and help mitigate volatility risk in any individual market. Through the fourth quarter of 2018, more than 50% of Tamarack's total natural gas production was priced at alternate US markets, including Malin, Chicago, Michigan Consolidated, Dawn and NYMEX daily index pricing less transportation tolls or fixed basis fees. Tamarack will continue to explore alternatives to minimize exposure to the historically weaker Alberta natural gas market.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
	2018	2017	% change	**2018**	2017	% change
Revenue ($ thousands)						
Oil and NGL	**$55,962**	$81,139	(31)	**$355,826**	$242,223	47
Natural gas	**17,113**	9,021	90	**42,978**	41,449	4
Total	**$73,075**	$90,160	(19)	**$398,804**	$283,672	41
Average realized price						
Light oil ($/bbl)	**36.78**	65.08	(43)	**64.17**	59.42	8
Heavy oil ($/bbl)	**49.33**	48.97	1	**59.13**	46.01	29
Natural gas liquids ($/bbl)	**33.72**	44.03	(23)	**41.89**	32.38	29
Combined average oil and NGL ($/boe)	**37.08**	62.34	(41)	**62.02**	55.36	12
Natural gas ($/mcf)	**3.70**	1.89	96	**2.30**	2.32	(1)
Revenue ($/boe)	**32.05**	42.97	(25)	**45.08**	38.60	17
Benchmark pricing:						
West Texas Intermediate (US$/bbl)	**58.79**	55.39	6	**64.78**	51.00	27
Edmonton Par (Cdn$/bbl)	**48.26**	66.86	(28)	**69.14**	62.23	11
Hardisty Heavy (Cdn$/bbl)	**34.23**	48.69	(30)	**49.95**	49.42	1
AECO daily index (Cdn$/mcf)	**1.55**	1.68	(8)	**1.49**	2.14	(30)
AECO monthly index (Cdn$/mcf)	**1.89**	1.95	(3)	**1.52**	2.41	(37)

Revenue from oil, natural gas and NGL sales for Q4/18 decreased 19% compared to the same period in 2017, primarily due to lower oil and NGL prices, partially offset by increased production volumes, an increase in oil weighting and an increase in realized natural gas prices.

For the year ended December 31, 2018, revenue from oil, natural gas and NGL sales increased 41% compared to the same period in 2017, primarily due to increased production volumes, increased oil weighting and higher oil and NGL 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 December 31, 2018, the Company held derivative commodity and foreign exchange contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	400 bbls/day	January 1, 2019 – March 31, 2019	WTI fixed price	US $63.10
Crude oil	700 bbls/day	April 1, 2019 – June 30, 2019	WTI fixed price	US $65.45
Crude oil	700 bbls/day	January 1, 2020 – March 31, 2020	WTI fixed price	US $66.96
Crude oil	4,140 bbls/day	January 1, 2019 – March 31, 2019	WTI put option	US $60.00
Crude oil	3,220 bbls/day	April 1, 2019 – June 30, 2019	WTI put option	US $60.00
Crude oil	3,105 bbls/day	July 1, 2019 – September 30, 2019	WTI put option	US $60.00
Crude oil	2,990 bbls/day	October 1, 2019 – December 31, 2019	WTI put option	US $60.00
Crude oil	4,000 bbls/day	January 1, 2019 – December 31, 2019	Edm par diff	US $12.13
Foreign exchange	6,750,000 US$/mth	January 1, 2019 – March 31, 2019	Exchange rate	Cdn $1.3074
Foreign exchange	6,750,000 US$/mth	April 1, 2019 – June 30, 2019	Exchange rate	Cdn $1.3046
Foreign exchange	5,750,000 US$/mth	July 1, 2019 – September 30, 2019	Exchange rate	Cdn $1.3065
Foreign exchange	4,750,000 US$/mth	October 1, 2019 – December 31, 2019	Exchange rate	Cdn $1.3111

At December 31, 2018, the commodity and foreign exchange contracts were fair valued with an asset value of $19.7 million (December 31, 2017 - $7.5 million liability) recorded on the balance sheet and an unrealized gain of $27.1 million recorded in earnings for the year ended December 31, 2018 (December 31, 2017 - $3.5 million unrealized gain). During Q4/18, the Company realized a $0.1 million gain on financial instruments and a $17.9 million loss for the year ended December 31, 2018, compared to a gain of $3.2 million and $5.6 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 December 31, 2018, the Company held the following physical commodity contracts:

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	25,000 mmbtu/day	January 1, 2019 – March 31, 2019	AECO/Henry Hub differential	Index – US $1.77
Natural gas	10,000 mmbtu/day	April 1, 2019 – October 31, 2019	AECO/Henry Hub differential	Index – US $1.60
Natural gas	5,000 mmbtu/day	November 1, 2019 – March 31, 2020	AECO/Henry Hub differential	Index – US $1.51

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

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	2,000 bbls/day	April 1, 2019 – June 30, 2019	Edm par diff	US $5.95

Since December 31, 2018, the Company has not entered into any physical contracts.

Royalties

Quarter-over-Quarter

	Q4 2018	Q3 2018	% change
Royalty expenses ($ thousands)	**$5,902**	$12,075	(51)
$/boe	**2.59**	5.30	(51)
percent of sales	**8**	10	(20)

Royalties as a percentage of revenue were lower in the fourth quarter of 2018 compared to the third quarter of 2018, largely caused by two factors: the sliding scale nature of some oil royalties which lowers the percent royalty paid when commodity prices are low; and an increased contribution of volumes from newly drilled locations on crown lands where royalty rates are fixed at 5% for an initial capital recovery period.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
	2018	2017	% change	**2018**	2017	% change
Royalty expenses ($ thousands)	**$5,902**	$8,464	(30)	**$39,901**	$29,134	37
$/boe	**2.59**	4.03	(36)	**4.51**	3.96	14
percent of sales	**8**	9	(11)	**10**	10	–

Royalties as a percentage of revenue were comparable for both the three months and year ended December 31, 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 2019 based on the current forecast commodity price levels.

Net Production and Transportation Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2018**	Q3 2018	% change
Production and transportation expenses	**$24,291**	$23,813	2
Less: processing income	**426**	170	151
Total net production and transportation expenses	**$23,865**	$23,643	1
Total ($/boe)	**$10.47**	$10.38	1

Net production and transportation expenses per boe for the fourth quarter of 2018 increased 1% compared to the third quarter of 2018. On an absolute basis, overall costs were marginally higher in the fourth quarter of 2018 compared to the third quarter of 2018 related to an increase in workovers offset by lower transportation costs due to the start-up of a midstream company's new 120 km pipeline (the "Viking Pipeline Project") which occurred in December, 2018.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2018**	2017	% change	**2018**	2017	% change
Production and transportation expenses	**$24,291**	$22,191	9	**$93,683**	$83,308	12
Less: processing income	**426**	373	14	**658**	1,069	(38)
Total net production and transportation expenses	**$23,865**	$21,818	9	**$93,025**	$82,239	13
Total ($/boe)	**$10.47**	$10.40	1	**$10.52**	$11.19	(6)

For the three months ended December 31, 2018, net production and transportation expenses per boe were comparable to the same period in 2017.

For the year ended December 31, 2018, net production and transportation expenses per boe were lower relative to the same period 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 period.

Tamarack entered into a commitment agreement on a take-or-pay basis to deliver at least 4,000 bbls/d of oil to 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. The Viking Pipeline Project has 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.

Operating Netback

Quarter-over-Quarter

($/boe)	**Q4 2018**	Q3 2018	% change
Average realized sales	**$32.05**	$52.29	(39)
Royalty expenses	**(2.59)**	(5.30)	(51)
Net production and transportation expenses	**(10.47)**	(10.38)	1
Operating field netback	**18.99**	36.61	(48)
Realized commodity hedging gain (loss)	**0.04**	(4.16)	(101)
Operating netback	**$19.03**	$32.45	(41)

As a result of the oil price dynamics that transpired during Q4/18 discussed above, the Company's operating netbacks (see "Non-IFRS Measures") for the period decreased 41% compared to the prior quarter. This decrease stems from a combination of lower wellhead pricing for crude oil and NGL, partially offset by an increase in realized natural gas pricing, a decrease in royalties and a realized commodity hedging gain compared to a realized hedging loss in the previous quarter.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($/boe)	**2018**	2017	% change	**2018**	2017	% change
Average realized sales	**$32.05**	$42.97	(25)	**$45.08**	$38.60	17
Royalty expenses	**(2.59)**	(4.03)	(36)	**(4.51)**	(3.96)	14
Net production and transportation expenses	**(10.47)**	(10.40)	1	**(10.52)**	(11.19)	(6)
Operating field netback	**18.99**	28.54	(33)	**30.05**	23.45	28
Realized commodity hedging gain (loss)	**0.04**	1.53	(97)	**(2.03)**	0.77	(364)
Operating netback	**$19.03**	$30.07	(37)	**$28.02**	$24.22	16

Similarly, Q4/18 operating netbacks decreased 37% over the same period in 2017 due to the lower wellhead pricing for crude oil and NGL as discussed above and a lower realized commodity hedging gain. These losses were partially offset by higher realized natural gas prices and lower royalties.

For the year ended December 31, 2018, operating netbacks increased 16% over the same period in 2017, supported by the Company's higher oil and NGL weighting, higher wellhead pricing for crude oil and NGL and lower net production and transportation expenses per boe. These gains were partially offset by a realized commodity hedging loss on financial derivative contracts in 2018 and higher royalties.

General and Administrative ("G&A") Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2018**	Q3 2018	% change
Gross costs	**$4,272**	$4,377	(2)
Capitalized costs and recoveries	**(934)**	(1,082)	(14)
General and administrative costs	**$3,338**	$3,295	1
Total ($/boe)	**$1.46**	$1.45	1

Gross and net G&A expenses remained consistent between the fourth quarter of 2018 and the third quarter of 2018. G&A expenses on a per boe basis remained consistent quarter-over-quarter.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2018**	2017	% change	**2018**	2017	% change
Gross costs	**$4,272**	$4,257	–	**$17,064**	$15,807	8
Capitalized costs and recoveries	**(934)**	(842)	11	**(3,678)**	(3,345)	10
General and administrative costs	**$3,338**	$3,415	(2)	**$13,386**	$12,462	7
Total ($/boe)	**$1.46**	$1.63	(10)	**$1.51**	$1.70	(11)

Gross G&A costs increased for the year ended December 31, 2018, compared to the same period in 2017, due to higher staffing levels required to effectively manage the increase in production. Net per boe G&A costs for both the three months and year ended December 31, 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)	**Q4 2018**	Q3 2018	% change
Gross costs	**$4,040**	$4,175	(3)
Capitalized costs	**(1,140)**	(1,177)	(3)
Total stock-based compensation	**$2,900**	$2,998	(3)
Total ($/boe)	**$1.27**	$1.32	(4)

Stock-based compensation expense related to stock options ("options") and restricted share unit awards ("RSUs") was similar in Q4/18 as Q3/18. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2018**	2017	% change	**2018**	2017	% change
Gross costs	**$4,040**	$1,618	150	**$12,471**	$6,357	96
Capitalized costs	**(1,140)**	(481)	137	**(3,598)**	(1,997)	80
Total stock-based compensation	**$2,900**	$1,137	155	**$8,873**	$4,360	104
Total ($/boe)	**$1.27**	$0.54	135	**$1.00**	$0.59	69

Stock-based compensation expense related to options and restricted share units ("RSU") was higher for the three months and year ended December 31, 2018 relative to the same periods in 2017, as higher staffing levels stemming from Tamarack's production growth through 2017 resulted in more RSU 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 year ended December 31, 2018, the Company issued 0.2 million options at a weighted average exercise price of $2.62 per share and issued 2.4 million RSU.

Interest Expense

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2018**	Q3 2018	% change
Interest on bank debt	**$1,706**	$2,063	(17)
Total ($/boe)	**$0.75**	$0.91	(18)
Average drawings on bank debt	**$159,286**	$155,131	3

Interest expense was lower in the fourth quarter of 2018 compared to the previous quarter, due to the increased utilization of lower interest rate options that were available through the Company's syndicate of lenders as well as favourable market conditions at year end.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2018**	2017	% change	**2018**	2017	% change
Interest on bank debt	**$1,706**	$2,097	(19)	**$8,072**	$7,093	14
Total ($/boe)	**$0.75**	$1.00	(25)	**$0.91**	$0.97	(6)
Average drawings on bank debt	**$159,286**	$175,373	(9)	**$158,898**	$150,873	5

Interest expense for the three months ended December 31, 2018 was lower than the same period in 2017 due to a lower average amount drawn on the revolving credit facility.

Interest expense for the year ended December 31, 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 on the revolving credit facility during 2018, associated with the Company's 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)	**Q4 2018**	Q3 2018	% change
Depletion and depreciation	**$44,498**	$45,409	(2)
Amortization of undeveloped leases	**328**	282	16
Accretion	**1,043**	1,041	-
Total	**$45,869**	$46,732	(2)
Depletion and depreciation ($/boe)	**$19.52**	$19.93	(2)
Amortization ($/boe)	**0.14**	0.12	17
Accretion ($/boe)	**0.46**	0.46	-
Total ($/boe)	**$20.12**	$20.51	(2)

DDA&A expense per boe for the fourth quarter of 2018 was lower compared to the third quarter of 2018. This decrease is due to the completion of the Company's year-end independent reserve evaluation which resulted in an increase in Tamarack's overall reserve base following the successful 2018 drilling program, better-than-expected well performance and additional reserves being added as a result of the Veteran waterflood project. On an absolute basis, DDA&A expense was lower due to the lower DDA&A expense per boe.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2018**	2017	% change	**2018**	2017	% change
Depletion and depreciation	**$44,498**	$41,569	7	**$176,498**	$147,862	19
Amortization of undeveloped leases	**328**	197	66	**1,078**	787	37
Accretion	**1,043**	1,035	1	**4,106**	3,741	10
Total	**$45,869**	$42,801	7	**$181,682**	$152,390	19
Depletion and depreciation ($/boe)	**$19.52**	$19.81	(1)	**$19.95**	$20.12	(1)
Amortization ($/boe)	**0.14**	0.09	56	**0.12**	0.11	9
Accretion ($/boe)	**0.46**	0.49	(6)	**0.46**	0.51	(10)
Total ($/boe)	**$20.12**	$20.39	(1)	**$20.53**	$20.74	(1)

For the three months and year ended December 31, 2018, DDA&A expense per boe was slightly lower relative to the same periods in 2017. The decrease was due to the completion of the Company's year-end independent reserve evaluation which resulted in an increase in Tamarack's overall reserve base following the successful 2018 drilling program, better-than-expected well performance and additional reserves being added as a result of the Veteran waterflood project. On an absolute basis, DDA&A expense was higher for the three months and year ended December 31, 2018 due to an increase in production volumes.

Income Taxes

The Company did not incur any cash tax expense in the three months or year ended December 31, 2018, nor does it expect to pay any cash tax in 2019 or 2020 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three months and year ended December 31, 2018, deferred income tax expense of $11.5 million and $20.8 million, respectively, were recognized compared to a deferred income tax recovery of $4.3 million and $3.6 million for the same respective periods in 2017.

The following table outlines the Company's estimated tax pools as at December 31, 2018:

Tax Pool Category	Deduction Rate	($ millions)
Canadian exploration expense (CEE)	100%	33
Canadian development expense (CDE)	30%	334
Canadian oil and gas property expense (COGPE)	10%	230
Non-capital losses (NCL)	100%	141
Undepreciated capital cost (UCC)	25%	131
Share issue costs and other	various	9
Total		878

Adjusted Operating Field Netback and Net Income (Loss)

Quarter-over-Quarter

($ thousands, except per share)	**Q4 2018**	Q3 2018	% change
Income before taxes	**$30,415**	$18,923	61
Depletion, depreciation and amortization	**44,826**	45,691	(2)
Stock-based compensation	**2,900**	2,998	(3)
Gain on disposition of property, plant and equipment	**(1,079)**	–	–
Accretion expense on decommissioning obligations	**1,043**	1,041	–
Unrealized gain on financial instruments	**(44,759)**	(74)	60,385
Impairment of property, plant and equipment, net	**5,000**	–	–
Adjusted operating field netback	**$38,346**	$68,579	(44)
Per share - basic	**$0.17**	$0.30	(43)
Per share - diluted	**$0.17**	$0.29	(41)
Net income	**$18,952**	$13,004	46
Per share - basic	**$0.08**	$0.06	33
Per share - diluted	**$0.08**	$0.06	33

The adjusted operating field netback (see "Non-IFRS Measures") during the fourth quarter of 2018 was lower than the third quarter of 2018 primarily due to 39% lower revenue from oil and natural gas sales caused by the extremely weak Canadian oil price market during the period, partially offset by a realized hedging gain in Q4/18 compared to a realized hedging loss in Q3/18.

The Company recorded increased net income of $19.0 million ($0.08 per share basic and diluted) during the three months ended December 31, 2018, compared to net income of $13.0 million ($0.06 per share basic and diluted) for the previous quarter. This was primarily due to a higher unrealized hedging gain in Q4/18 compared to Q3/18, partially offset by 39% lower revenue from oil and natural gas sales, higher deferred tax expense and a net impairment to property, plant and equipment.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per share)	**2018**	2017	% change	**2018**	2017	% change
Income (loss) before taxes	**$30,415**	$(16,851)	(280)	**$59,142**	$(17,535)	(437)
Depletion, depreciation and amortization	**44,826**	41,766	7	**177,576**	148,649	19
Stock-based compensation	**2,900**	1,137	155	**8,873**	4,360	104
Gain on disposition of property, plant and equipment	**(1,079)**	–	–	**(1,085)**	–	–
Transaction costs	**–**	–	–	**–**	5,663	(100)
Accretion expense on decommissioning obligations	**1,043**	1,035	1	**4,106**	3,741	10
Unrealized loss (gain) on financial instruments	**(44,759)**	13,496	(432)	**(27,137)**	(3,495)	676
Impairment of property, plant and equipment, net	**5,000**	17,000	(71)	**5,000**	17,000	(71)
Adjusted operating field netback	**$38,346**	$57,583	(33)	**$226,475**	$158,383	43
Per share - basic	**$0.17**	$0.25	(32)	**$0.99**	$0.70	41
Per share - diluted	**$0.17**	$0.25	(32)	**$0.97**	$0.70	39
Net income (loss)	**$18,952**	$(12,525)	(251)	**$38,310**	$(13,924)	(375)
Per share - basic	**$0.08**	$(0.05)	(260)	**$0.17**	$(0.06)	(383)
Per share - diluted	**$0.08**	$(0.05)	(260)	**$0.16**	$(0.06)	(367)

Fourth quarter 2018 adjusted operating field netback (see "Non-IFRS Measures") was lower on an absolute basis than the same period in 2017, primarily due to lower crude oil prices.

For the full year 2018, adjusted operating field netback (see "Non-IFRS Measures") was higher on an absolute basis than the same period in 2017, primarily due to increased production, higher 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 $19.0 million ($0.08 per share basic and diluted) and $38.3 million ($0.17 per share basic and $0.16 per share diluted) during the three months and year ended December 31, 2018, respectively, compared to a net loss of $12.5 million ($0.05 per share basic and diluted) and $13.9 million ($0.06 per share basic and diluted) for the same periods in 2017. This was primarily due to increased production, higher crude oil prices and operating netbacks, the unrealized hedging gains that occurred in 2018, partially offset by deferred tax expense and higher depletion, depreciation and amortization charges.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

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

($ thousands)	Three months ended December 31, 2018	2017	% change	Years ended December 31, 2018	2017	% change
Land	**$42**	$(174)	(124)	**$4,690**	$1,708	175
Geological and geophysical	**–**	–	–	**13**	2,022	(99)
Drilling and completion	**15,254**	26,378	(42)	**167,216**	143,802	16
Equipment and facilities	**9,664**	8,591	12	**51,254**	41,766	23
Capitalized G&A	**791**	687	15	**2,861**	2,670	7
Office equipment	**47**	34	38	**217**	334	(35)
Total capital expenditures	**$25,798**	$35,516	(27)	**$226,251**	$192,302	18

In response to the rapid and extreme widening of Canadian oil price differentials that occurred in Q4/18, Tamarack elected to defer $7.0 million of the $28.4 million in capital spending that had previously been planned for acceleration from 2019 into Q4/18. As a result, the Company's Q4/18 capital spending totaled $25.8 million, bringing its total annual capital investment to $226.3 million ($219.2 million net of acquisitions and dispositions). During the fourth quarter of 2018, the Company drilled, completed and equipped five (4.8 net) Viking oil wells plus one water source well in the Veteran area. In addition to the fourth quarter drilling program, the Company also completed and brought on production wells that were drilled in late Q3/18 including 18 (17.8 net) Viking oil wells and one (1.0 net) Penny oil well. The Company also drilled 19 (18.5 net) Viking oil wells that will be brought on production in the first quarter of 2019, resulting in total drilling for the quarter of 24 (23.2 net) Viking oil wells and one (1.0 net) water source well.

Tamarack also directed capital to the continued development of a waterflood program in the Company's Veteran, Alberta area. Of the 24 Viking oil wells drilled at Veteran in the quarter, six wells are future injection wells, which will produce to recover the capital costs until the commencement of the injection project in the first half of 2019. Additionally, significant investment in area pipeline and facility infrastructure that is required to operate the infield waterflood was initiated and continued through the end of 2018 and into early 2019. The waterflood 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.

	2018 Drilling Summary		2017 Drilling Summary	
	Gross	Net	Gross	Net
Viking	129.0	124.7	104.0	99.0
Cardium	19.0	17.8	16.0	15.3
Redwater	11.0	10.7	4.0	3.1
Penny	4.0	4.0	1.0	1.0
Other	1.0	1.0	8.0	8.0
	164.0	158.2	133.0	126.4

As at December 31, 2018, the Company's net undeveloped land totaled 413,008 acres.

Property Acquisitions and Dispositions

In the fourth quarter of 2018, Tamarack completed two dispositions for total proceeds of $4.9 million. No production was associated with these disposed assets.

During the year ended December 31, 2018, Tamarack completed one tuck-in acquisition for $2.8 million and three dispositions for proceeds of $9.9 million. The acquisition added 18 boe/d and 3.3 (2.1 net) sections of undeveloped land. The disposed assets did not have any associated production.

Impairment

An impairment charge (net of recovery) of $5.0 million (December 31, 2017 – $17.0 million) was recorded as at December 31, 2018 on the Company's PP&E. The impairment charge is primarily the result of a decrease in current and forecast natural gas prices. The impairment recognized relates to the Company's Cardium Oil ($58.0 million) cash-generating unit ("CGU") that has associated natural gas being produced with the oil and includes Mannville gas wells and a Pekisko gas unit. The recoverable amount of this CGU as at December 31, 2018 was based on the net present value of before tax cash flows from proved plus probable reserves estimated by the Company's independent reserves evaluator at discount rates specific to the underlying composition of reserve categories of 8% to 15%. There was also an impairment reversal in the Viking Oil CGU in the amount of $53.0 million due to increased reserves and a reduction in future drilling costs per well and was based on the net present value of before tax cash flows from proved plus probable reserves estimated by the Company's independent reserves evaluator at discount rates specific to the underlying composition of reserve categories of 8% to 15%. During the years of 2014 and 2015 the Viking Oil CGU was tested for impairment due to decreased oil prices which resulted in impairments in the amount of $74.0 million. The recoverable amount of Tamarack's CGUs was determined using the fair value less costs of disposal methodology based on what Tamarack could receive for these assets if it disposed of them in the current environment taking into account the increase to the volatility of oil differentials and lower natural gas prices.

Share Capital

At December 31, 2018, Tamarack had 226,072,693 common shares, 1,193,188 common shares held in treasury, 2,944,833 options and 7,407,472 RSU outstanding. At February 26, 2019, there were 226,348,750 common shares, 819,731 common shares held in treasury, 2,944,833 options and 7,074,015 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 RSU outstanding. No preferred shares of Tamarack are issued and outstanding.

At December 31, 2018, there were 1,086,974 preferred shares of Tamarack Acquisition Corp. ("TAC Preferred Shares") which are exchangeable into 1,045,168 common shares of the Company and at December 31, 2017, there were 1,155,007 preferred shares of Tamarack Acquisition Corp. which were exchangeable into 1,110,584 common shares of the Company. The TAC Preferred Shares are fully vested at December 31, 2018 and are exchangeable into common shares of Tamarack at an exchange price of $3.12 per common share. For the year ended December 31, 2018, 68,033 TAC Preferred Shares expired.

As noted under 'Liquidity and Capital Resources' below, during the year ended December 31, 2018, Tamarack purchased and cancelled 3,025,000 outstanding common shares under its normal course issuer bid ("NCIB") program, for a total investment of $11.7 million. 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 year ended December 31, 2018, the Company also directed $5.8 million to the purchase of 1,803,592 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 December 31, 2018, the balance of the remaining common shares held in trust totaled 1,193,188.

Liquidity and Capital Resources

($ thousands)	**December 31, 2018**	December 31, 2017	September 30, 2018
Working capital deficiency	**$18,385**	$9,291	$23,214
Bank debt	**161,495**	163,889	168,970
Net debt	**179,880**	173,180	192,184
Quarterly adjusted funds flow	**$38,346**	$57,583	$68,579
Annualized factor	**4**	4	4
Annualized adjusted funds flow	**153,384**	230,332	274,316
Net debt to annualized adjusted funds flow	**1.2x**	0.8x	0.7x

Tamarack's net debt (see "Non-IFRS Measures"), including working capital deficiency but excluding the fair value of financial instruments, totaled $179.9 million as at December 31, 2018. This compares to net debt of $192.2 million and $173.2 million in the previous quarter and the fourth quarter of 2017, respectively. Tamarack's Q4/18 net debt to annualized adjusted operating field netback ratio was 1.2 times.

The $21.0 million of capital expenditures and property acquisitions, net of dispositions, invested during the fourth quarter of 2018 was funded entirely by Tamarack's adjusted operating field netback of $38.3 million. The excess $17.3 million adjusted operating field netback, plus the $0.5 million proceeds from exercised options, funded the $2.3 million of share purchases under the NCIB, $1.8 million of shares purchased to be held in treasury to offset future dilution from potential RSU settlements, $1.5 million of abandonments and the remaining $12.3 million reduced net debt.

The $219.2 million of capital expenditures and property acquisitions, net of dispositions, invested during the year ended December 31, 2018 was funded entirely by Tamarack's adjusted operating field netback of $226.5 million. The excess $7.3 million adjusted operating field netback, plus $5.4 million in proceeds from exercised options and $6.7 million of increased net debt, collectively funded the $11.7 million of share purchases under the NCIB, $5.8 million of shares purchased to be held in treasury to offset future dilution from potential RSU settlements and $1.9 million of abandonments.

With continued commodity price volatility and crude oil price differential volatility recently impacting the Canadian oil and gas industry, Tamarack's strategy remains focused on preserving balance sheet strength. The Company strives to achieve this by adjusting capital spending as appropriate to respond to changes in realized commodity prices and by using financial derivatives and physical delivery contracts to mitigate risk. Tamarack intends to maintain balance sheet flexibility which allows the Company to be opportunistic and take advantage of potential opportunities within core areas, whether by increasing drilling activity or by completing tuck-in acquisitions. 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 the NCIB through the facilities of the Toronto Stock Exchange and alternate trading platforms, pursuant to which the Company 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 December 31, 2018, the Company spent $11.7 million to purchase and cancel 3,025,000 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").

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, of which $161.5 million is drawn as of December 31, 2018 (December 31, 2017 - $163.9 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.

During the semi-annual review of the Facility that occurred in the fourth quarter of 2018, 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. As at December 31, 2018, the accordion has not been 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 December 31, 2018, the Facility was secured by a $1.0 billion supplemental debenture with a floating charge over all assets. As the available lending limits of the Facility are based on the bank's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review is scheduled for May 2019.

There are no financial covenants governing the Facility.

Guidance

Tamarack's fourth quarter production averaged 24,780 boe/d (oil and NGL weighting of 66%) which was in line with its exit guidance range of 24,500 to 25,000 boe/d (oil and NGL weighting 65 to 67%). Average annual production for 2018 of 24,237 boe/d was also in line with guidance of 24,000 to 24,500 boe/d (64 to 66% oil and NGL) despite spending $219 million, net of acquisitions and dispositions, which was $9 million less than the mid-point of guidance.

Tamarack's capital allocation strategy over the past several years has remained consistent with the objective of achieving sustainability at low oil prices, while generating debt-adjusted per share growth. Due to the Company's success in accumulating an inventory of Viking and Cardium locations that payout in 1.5 years or less at current commodity prices, Tamarack expects to be fully self-funding in 2019 and estimates it will achieve 3-5% debt-adjusted production per share[1] growth (see "Non-IFRS Measures") in Q4/19 over Q4/18. The Company remains well positioned to withstand further crude oil price volatility given approximately 30% of its 2019 production is protected with hedges that include a US$60.00/bbl WTI put option with another approximately 3% protected by fixed price contracts at US$64.60/bbl.

Tamarack plans to invest between $170 and $180 million in its 2019 capital expenditures, funded entirely through adjusted operating field netback. This capital program is expected to result in stable year over year average production of 23,500 – 24,500 boe/d (oil and NGL weighting 64 to 66%), while spending approximately 23% less than in 2018. The Company's 2019 budget anticipates drilling 125 net wells, including 110 Viking light oil wells (94 of which will be at Veteran), 13 Cardium light oil wells and two wells at Penny. In addition, the 2019 budget includes $19.8 million of waterflood investments, including 15 well conversions in H1/19 and the drilling and conversion of six additional injection wells in East Veteran. In the context of continued volatility in oil prices and supported by the Company's exceptional operational execution, Tamarack remains committed to investing in longer-term projects, including the Veteran waterflood, which the Company expects will reduce the overall corporate decline rate in 2020 and further enhance Tamarack's sustainability.

Effective January 1, 2019, the Alberta government imposed mandatory oil curtailments designed to mitigate the wide price differential related to a lack of pipeline capacity, which is ultimately expected to lead to stronger oil prices. While the Company's 2019 capital guidance assumes activity levels will be weighted evenly between the first and second halves of 2019, the timing of capital allocation in H1/19 has been designed to comply with the required production cuts. As a result, approximately 65% of the drilling program will occur in the H2/19. Following expected stable production levels in H1/19 stemming from the mandatory volume curtailments, Tamarack anticipates realizing a meaningful ramp-up in production volumes during H2/19, assuming no additional government intervention.

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[1] Debt-adjusted production per share is a measure of changes in production on a per share basis, with the number of shares adjusted based on changes to net debt outstanding for the periods being compared. Debt adjusted share count is calculated as total shares outstanding plus incremental shares issued using $2.30 per share to eliminate the change in net debt or in the case where net debt decreases the reduction in shares using the same $2.30 per share.

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

	2019 Budget
Average annual production (boe/d)	23,500 – 24,500
Liquids weighting (%)	~64 - 66
Exit production (boe/d)	25,500 – 26,500
Liquids weighting (%)	~64 – 66
2019 Capital expenditures ($millions)	$170 - $180
2019 price assumptions:	
WTI ($US/bbl)	$50.00
Edmonton Par ($CDN/bbl)	$52.33
Edmonton Par differential ($US/bbl)	$10.75
AECO ($CDN/GJ)	$1.31
Canadian/US dollar exchange rate	$0.75

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 December 31, 2018:

($ thousands)	2019	2020	2021	2022	2023	2024	2025+
Bank debt	-	161,495	–	–	–	–	–
Office lease	542	263	–	–	–	–	–
Take or pay commitments(1)	2,205	2,256	2,294	2,340	2,396	–	–
Rental fee(2)	6,312	6,312	6,312	4,441	2,570	1,142	1,285
Gas transportation(3)	730	229	76	–	–	–	–
Total	9,789	170,555	8,682	6,781	4,966	1,142	1,285

(1) Pipeline commitment to deliver a minimum of 636 m^3/d of crude oil/condensate subject to a take-or-pay provision of $9.00/$m^3$. 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”, “operating field netback”, “net debt”, “netbacks”, “capital cost payout”, “net debt to annualized adjusted operating field netback ratio” and “debt adjusted production per share growth”, 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.

(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. Adjusted operating field netback per share is calculated using the same weighted average basic and diluted shares used in calculating income (loss) per share. The calculation of the Company’s adjusted operating field netbacks are summarized starting on page 12 in the section titled “Adjusted Operating Field Netback and Net Income (Loss)”.

(b) **Operating Netback and Operating Field netback** - Management uses certain industry benchmarks, such as operating netback and operating field netback, to analyze financial and operating performance. These benchmarks do not have standardized meanings 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 and foreign exchange derivative contracts, less royalties and net production and transportation costs. Operating field netback equals total petroleum and natural gas sales, less royalties and net production and transportation costs. These metrics can also be calculated on a per boe basis. Management considers operating netback and operating field netback important measures 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. 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. Management considers net debt an important measure to assist in assessing the liquidity of the Company.

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

($ thousand)	December 31, 2018	December 31, 2017
Accounts payable and accrued liabilities	$41,966	$51,059
Accounts receivable	(21,211)	(38,673)
Prepaid expenses and deposits	(2,370)	(3,095)
Working capital deficiency	18,385	9,291
Bank debt	161,495	163,889
Net debt	$179,880	$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.

(e) **Net debt to annualized adjusted operating field netback** – Management uses certain industry benchmarks, such as net debt to annualized adjusted operating field 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. This benchmark is calculated as net debt divided by the annualized adjusted operating field netback for the most recently completed quarter. Management considers net debt to annualized adjusted operating field netback as a key measure as it provides a snapshot of the overall financial health of a company and its ability to pay off its debt and take on new debt, if necessary, using the most recent quarter's results.

(f) **Debt adjusted production per share growth -** Management uses certain measurements as debt adjusted production per share growth, 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. This is a measure of changes in production on a per share basis, with the number of shares adjusted based on changes to net debt outstanding for the periods being compared. Debt-adjusted share count is calculated as total shares outstanding plus incremental shares issued at a current market price to eliminate the change in net debt or in the case where debt decreases the reduction in shares. Management of Tamarack believes that debt adjusted production per share is useful in determining the production growth on a per share basis as if changes to debt was extinguished by the issuance or redemption of shares. The presentation of production growth on a per share basis is skewed for oil and gas companies that have more debt on their balance sheet and in their capital structure. Such companies will show better results because more of their growth is financed through debt than equity (as opposed to generating growth through realizing a rate of return on capital employed). The debt adjusted production per share measure provides a means of putting oil and gas companies on an equal, enterprise-based footing with respect to debt when calculating per share numbers. This measure is relevant to investors to appreciate the impact the debt on a company's balance sheet has on per share growth disclosure and the strength of one company's balance sheet relative to an over-leveraged peer, particularly in volatile commodity price environments where a company's indebtedness may increase as a result of lower cash flows and higher debt financing costs.

Selected Quarterly Information

Three months ended	**Dec. 31, 2018**	Sep. 30, 2018	Jun. 30, 2018	Mar. 31, 2018	Dec. 31, 2017	Sep. 30, 2017	Jun. 30, 2017	Mar. 31, 2017
Sales volumes								
Natural gas *(mcf/d)*	**50,262**	49,943	52,376	51,879	51,956	49,987	47,696	45,852
Oil and NGL *(bbls/d)*	**16,403**	16,441	15,124	14,885	14,148	12,210	11,387	10,154
Average boe/d *(6:1)*	**24,780**	24,765	23,853	23,532	22,807	20,541	19,336	17,796
Product prices								
Natural gas *($/mcf)*	**3.70**	1.63	1.65	2.25	1.89	1.62	3.01	2.89
Oil and NGL *($/bbl)*	**37.08**	73.81	72.66	65.86	62.34	50.29	51.77	55.74
Oil equivalent *($/boe)*	**32.05**	52.29	49.69	46.62	42.97	33.83	37.91	39.25
(000s, except per share amounts)								
Financial results								
Gross revenues	**73,075**	119,134	107,859	98,736	90,160	63,927	66,715	62,870
Cash provided by operating activities	**49,137**	62,644	64,606	60,285	50,056	35,237	34,537	24,695
Adjusted operating field netback (1)	**38,346**	68,579	61,005	58,545	57,583	34,774	33,670	32,356
Per share – basic	**0.17**	0.30	0.27	0.26	0.25	0.15	0.15	0.15
Per share – diluted	**0.17**	0.29	0.26	0.25	0.25	0.15	0.15	0.15
Net income (loss)	**18,952**	13,004	3,060	3,294	(12,525)	(6,742)	3,053	2,290
Per share – basic	**0.08**	0.06	0.01	0.01	(0.05)	(0.03)	0.01	0.01
Per share – diluted	**0.08**	0.06	0.01	0.01	(0.05)	(0.03)	0.01	0.01
Capital expenditures	**25,798**	78,149	52,674	69,630	35,516	74,063	19,002	63,721
Net acquisitions (dispositions)	**(4,823)**	–	(5,009)	2,790	1,713	2,962	1,301	75,995
Total assets	**1,264,053**	1,291,058	1,237,571	1,240,335	1,207,809	1,206,886	1,178,404	1,186,285
Net debt(1)	**179,880**	192,184	181,341	186,732	173,180	194,917	152,354	165,561
Bank debt	**161,495**	168,970	156,965	165,750	163,889	162,164	140,795	135,484
Decommissioning obligations	**193,003**	192,409	185,038	182,216	177,793	167,102	171,909	164,012

(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 and foreign exchange rates 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 a net impairment charge on its Cardium oil cash-generating unit ("CGU") that has associated natural gas being produced with the oil and includes Mannville gas wells and a Pekisko gas unit, due to falling gas prices in the amount of $58.0 million in Q4 2018 and an impairment reversal of $53.0 million on its Viking oil CGU. The Company recorded impairment charges on its heavy oil and certain natural gas related CGU due to falling oil and gas prices in the amount of $17.0 million in Q4 2017.

Selected Annual Information

Years ended December 31,	**2018**	2017	2016
Sales volumes			
Natural gas *(mcf/d)*	**51,108**	48,893	28,388
Oil and NGL *(bbls/d)*	**15,719**	11,987	5,613
Average boe/d *(6:1)*	**24,237**	20,136	10,344
Product prices			
Natural gas *($/mcf)*	**2.30**	2.32	2.41
Oil and NGL *($/bbl)*	**62.02**	55.36	44.06
Oil equivalent *($/boe)*	**45.08**	38.60	30.51
(000s, except per share amounts)			
Financial Results			
Gross revenues	**398,804**	283,672	115,517
Net income (loss)	**38,310**	(13,924)	(27,823)
Per share – basic	**0.17**	(0.06)	(0.23)
Per share – diluted	**0.16**	(0.06)	(0.23)
Capital expenditures	**226,251**	192,302	56,819
Net acquisitions (dispositions)	**(7,042)**	81,971	82,862
Total assets	**1,264,053**	1,207,809	663,564
Net debt[1]	**179,880**	173,180	52,316
Bank debt	**161,495**	163,889	45,227

[1] Refer to definition of net debt under "Non-IFRS Measures".

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

- The volatility in commodity prices and the resultant effect on revenue, cash provided by operating activities and earnings.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices and foreign exchange rates 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 which added assets in Southeast

Alberta and Southwest Saskatchewan; in 2017 this acquisition added $62.3 million to oil and natural gas revenue and contributed $1.1 million to net loss.

- During the third quarter of 2016, Tamarack closed the strategic Penny and Redwater Acquisitions; in 2016 these acquisitions added $15.4 million to oil and natural gas revenue and contributed $0.1 million to the net loss.
- The Company recorded $5.7 million in transaction costs in the first quarter of 2017 related to the Viking Acquisition and recorded $0.6 million in transaction costs in the third quarter of 2016 related to the Penny and Redwater Acquisitions.
- The Company recorded a net impairment charge on its Cardium oil CGU that has associated natural gas being produced with the oil and includes Mannville gas wells and a Pekisko gas unit, due to falling gas prices in the amount of $58.0 million in Q4 2018 and an impairment reversal of $53.0 million on its Viking oil CGU. The Company recorded impairment charges on its heavy oil and certain natural gas related CGUs due to falling oil and gas prices in the amount of $17.0 million in 2017 and $0.7 million of exploration and evaluation asset impairment in 2016.

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 ("E&E") –** 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/or 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.

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. 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.

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

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

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. Cash flows associated with lease repayments will be allocated between operating and financing activities based on their interest repayment and principal repayment portions. 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 the Company on January 1, 2019. 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 currently completing its review and analysis of the significant lease contracts that fall into the scope of the new standard. The Company expects adjustments for surface land rights, certain leased vehicles and field equipment, however, the full extent of the impact has not yet been finalized as the Company has not completed reviewing all of the contracts that it has in place.

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 December 31, 2018 that have materially affected, or are reasonably likely to materially affect, the Company’s internal controls over financial reporting. As a result, the Company’s DCP and its ICFR were effective as at December 31, 2018.

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. For a more fulsome risk discussion, refer to Tamarack’s AIF, which can be found on SEDAR at www.sedar.com.

Financial Risks

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

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

Operational Risks

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

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

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

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

Regulatory Risks

Regulatory risks include the possibility of changes to royalty, tax, environmental 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;
- continued issues related to commodity price differentials, market oversupply and Canadian infrastructure restrictions and the impact of the Government of Alberta's production curtailments and production management from the producer community thereon;
- the availability, size, terms, use and renewal of the Facility;

- estimated production rates in 2019, 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 and by using financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates;
- Tamarack's intent to maintain balance sheet flexibility to allow the Company to take advantage of opportunities within the core areas, whether by increasing drilling activity or by completing tuck-in acquisitions;
- Tamarack's primary focus areas for production growth;
- future drilling plans;
- 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;
- the estimates used to calculate the decommissioning obligations and depletion of PP&E;
- the Company's capital budget program and guidance 2019 and the weighting of activity levels between the first and second halves of 2019;
- share buy-backs for cancellation under the NCIB and RSU settlements;
- 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 2019 price assumptions;
- expectations for oil, NGL and natural gas pricing in 2019 and beyond; and
- expectations for oil, NGL and natural gas weighting in 2019.

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 "Unit Cost Calculation", "Non-IFRS Measures", "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", "Impairment", "Share Capital", "Liquidity and Capital Resources", "Bank Debt", "Guidance", "Commitments", "Selected Quarterly Information" and "Selected Annual 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, 2018, 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.