



## MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the three months and years ended December 31, 2019 and 2018. This MD&A is dated and based on information available as at March 4, 2020 and should be read in conjunction with the audited consolidated financial statements ("financial statements") and the notes thereto for the years ended December 31, 2019 and 2018. Additional information relating to Tamarack, including Tamarack's Annual Information Form for the year ended December 31, 2019, is available on SEDAR at [www.sedar.com](http://www.sedar.com) and Tamarack's website at [www.tamarackvalley.ca](http://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 21. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

### **Q4 and Year End 2019 Financial and Operating Highlights**

- Achieved stable quarterly production volumes of 24,859 boe/d in Q4/19, slightly higher than the Q4/18 average of 24,780 boe/d and 3% higher than the previous quarter, and annual volumes of 24,072 boe/d, while generating free adjusted funds flow (see "Non-IFRS Measures") of \$40.5 million in 2019.
- Generated adjusted funds flow (previously referred to as "adjusted operating field netback"; see "Non-IFRS Measures") of \$219.4 million in 2019 (\$0.97 per share basic and diluted), compared to \$226.5 million in 2018 (\$0.99 per share basic and \$0.97 per share diluted). Q4/19 adjusted funds flow was \$54.7 million, an increase of \$16.4 million, or 43%, over the same period in 2018.
- Invested \$179.0 million in capital expenditures, excluding acquisitions, during 2019 which contributed to the drilling of 149 (144.5 net) wells, comprised of 127 (124.1 net) Viking oil wells, 14 (12.5 net) Cardium oil wells, two (2.0 net) Penny Barons oil wells and six (5.9 net) water source and injector wells, as well as bringing wells drilled in Q4/18 onto production in 2019.
- Directed free adjusted funds flow to key projects such as tuck-in acquisitions and the Company's active share repurchase program which included: \$8.3 million to purchase and cancel 4.2 million shares; and, \$3.5 million to purchase an additional 1.6 million shares to be held in trust by Tamarack's trustee for future restricted share units ("RSUs") settlement, offsetting RSU dilution and supporting debt-adjusted per share metrics.

- Reduced net debt by 11% quarter-over-quarter to \$189.5 million, including working capital deficiency but excluding the fair value of financial instruments and lease liabilities, resulting in a 2019 net debt to annualized adjusted funds flow ratio (see “Non-IFRS Measures”) of 0.9 times.
- Held Tamarack’s oil and natural gas liquids (“NGL”) weighting stable at 63% year-over-year, while spending \$30.3 million less in capital, after acquisitions and dispositions, with an 8% increase in incremental oil production over Q3 incremental and increasing waterflood production.
- Generated higher operating netbacks (see “Non-IFRS Measures”) in Q4/19 relative to Q4/18 and Q3/19 due in part to Tamarack’s ongoing focus on cost controls, while slightly lower annual operating netbacks in 2019 compared to 2018 reflects the impact of lower natural gas prices, offset by reductions in net production and transportation expenses stemming primarily from increased production from the lower-cost Veteran area.

## Production

<b>Quarter-over-Quarter</b>			
	<b>Q4 2019</b>	Q3 2019	<b>% change</b>
Production			
Light oil (bbls/d)	<b>13,729</b>	12,748	8
Heavy oil (bbls/d)	<b>318</b>	440	(28)
Natural gas liquids (bbls/d)	<b>1,735</b>	1,779	(2)
Natural gas (mcf/d)	<b>54,462</b>	55,224	(1)
Total (boe/d)	<b>24,859</b>	24,171	3
Percentage of oil and NGL	<b>63%</b>	62%	2

Average production for Q4/19 increased 3% from the previous quarter as a result of 11 net Viking oil wells coming on-stream that were drilled and awaiting completion at the end of Q3/19, plus 15 gross (14.6 net) Viking oil wells that were drilled and came on-stream in Q4/19. Rather than shut-in wells to comply with the Curtailment Order, Tamarack adjusted the timing of drilling and completion activity during 2019 and relied on the expected base production declines to remain below the imposed production limits. On August 20, 2019, the Government of Alberta announced that the Curtailment Order would extend to December 31, 2020, with possible early termination, and that the base limit for curtailment would increase from 10,000 to 20,000 bbls/d effective October 1, 2019 (the “Curtailment Limit Increase”). Due to the Curtailment Limit Increase, Tamarack ceased to be subject to the Curtailment Order commencing in October of 2019, and continues to be exempt from the Curtailment Order based on its current Alberta production levels of approximately 13,000 bbls/d. During the fourth quarter, the Company’s drilling program added 2,068 boe/d in Veteran (80% oil and NGL weighting).

In Q4/19, the Company’s average oil and NGL weighting increased to 63% compared to 62% in Q3/19.

## Year-over-Year

	Three months ended December 31,			Years ended December 31,		
	2019	2018	% change	2019	2018	% change
Production						
Light oil (bbls/d)	13,729	14,163	(3)	13,103	13,769	(5)
Heavy oil (bbls/d)	318	755	(58)	440	552	(20)
Natural gas liquids (bbls/d)	1,735	1,485	17	1,622	1,398	16
Natural gas (mcf/d)	54,462	50,262	8	53,444	51,108	5
Total (boe/d)	24,859	24,780	–	24,072	24,237	(1)
Percentage of oil and NGL	63%	66%	(5)	63%	65%	(3)

Average production for Q4/19 and the year ended 2019 was similar to the same periods in 2018. The Company's oil and NGL weighting was lower for Q4/19 and the year ended 2019 relative to the same periods in 2018 due to the Company adjusting the timing of its capital investment and activity in order to comply with the Curtailment Order.

## Petroleum and Natural Gas Sales

### Quarter-over-Quarter

	Q4 2019	Q3 2019	% change
Revenue (\$ thousands)			
Oil and NGL	\$86,398	\$81,771	6
Natural gas	11,301	7,808	45
Total	\$97,699	\$89,579	9
Average realized price:			
Light oil (\$/bbl)	64.26	65.10	(1)
Heavy oil (\$/bbl)	58.96	56.74	4
Natural gas liquids (\$/bbl)	21.96	19.08	15
Combined average oil and NGL (\$/boe)	59.51	59.38	–
Natural gas (\$/mcf)	2.26	1.54	47
Revenue (\$/boe)	42.72	40.28	6
Benchmark pricing:			
West Texas Intermediate (US\$/bbl)	56.91	56.39	1
Edmonton Par (Cdn\$/bbl)	66.86	69.18	(3)
Hardisty Heavy (Cdn\$/bbl)	50.06	57.99	(14)
NYMEX monthly settlement (US\$/mmbtu)	2.62	2.23	17
AECO daily index (Cdn\$/mcf)	2.46	0.91	170
AECO monthly index (Cdn\$/mcf)	2.32	1.04	123

Revenue from oil, natural gas and NGL sales in Q4/19 was 6% higher per boe than in Q3/19 primarily due to improved pricing. In response to a continued lack of pipeline takeaway capacity in Canada, the Curtailment Order was implemented in late 2018. The associated production curtailments, combined with active production management and engagement from the producer community, resulted in a significant narrowing of the WTI/Edmonton Par differential through 2019.

Although WTI increased steadily from its lows at the beginning of Q4/19, crude markets on average were relatively flat from Q3/19 to Q4/19, increasing only 1% to average US \$56.91/bbl compared to US \$56.39/bbl in the prior quarter. The WTI/Edmonton Par light oil differential widened through Q4/19, averaging US \$5.39/bbl compared to US \$4.68/bbl in Q3/19. This widening, in combination with the strengthening Canadian dollar relative to the US dollar, resulted in a 3% reduction in the average Edmonton Par price of \$66.86/bbl in Q4/19 compared to Cdn \$69.18/bbl in Q3/19. Tamarack's realized light oil wellhead price for the three months ended December 31, 2019 decreased 1% to \$64.26/bbl from \$65.10/bbl in the previous quarter, slightly ahead of the benchmark for the same period.

Although the light sweet differential has largely stabilized, Tamarack believes potential differential widening and volatility poses a continued risk to Canadian crude prices through 2020. The Government of Alberta has indicated that the Curtailment Order could remain in place until December 31, 2020; however, its future direction is uncertain and any changes to the current regulations could result in a material change to prices as a whole. In addition, negative sentiment due to an uncertain prognosis for additional pipeline capacity out of Western Canada presents further pricing risk. Tamarack has differential hedges protecting approximately 50% of forecasted oil production in 2020. Pricing is also highly susceptible to global macroeconomic events, as demonstrated by the recent volatility in the oil markets, with oil prices dropping dramatically subsequent to year end. While the timing, duration and magnitude of extreme oil price conditions are difficult to predict, Tamarack is committed to conservative planning and continues to explore strategies to mitigate and manage market risk through financial and physical hedges as well as alternate market delivery and pricing options.

Realized NGL prices increased 15% to \$21.96/bbl in Q4/19 from \$19.08/bbl in Q3/19. The increase is due to a combination of factors including increased WTI pricing in the quarter, which is the basis for condensate and butane pricing, as well as improved condensate differentials and stronger propane pricing through the later part of the quarter. While depressed butane pricing and increased fractionation fees for the 2019 to 2020 contract season have significantly reduced realized prices year-over-year, the market improvements did generate some quarter-over-quarter gains. Similar to other commodities, NGL supply has overwhelmed demand in the Alberta market and prices have been impacted by a lack of pipeline egress in Canada. However, Tamarack anticipates some minor improvements in NGL pricing due to market recoveries for the next contract year, which begins April 1, 2020.

Tamarack's realized natural gas price increased 47% to \$2.26/mcf in Q4/19 from \$1.54/mcf in Q3/19. The AECO daily benchmark price increased 170% to \$2.46/mcf in Q4/19 from \$0.91/mcf in Q3/19 and the NYMEX monthly settlement price increased 17% to US \$2.62/mmbtu in Q4/19 from US \$2.23/mmbtu in Q3/19. The increase in the Company's Q4/19 realized price compared to the previous quarter is due to expected increases in seasonal demand as well as near-term price increases in the Alberta market due to regulatory changes. Tamarack's value increase deviates from the increases seen in the two indices due to the Company's diversification strategy that balances its pricing exposure over multiple markets. While this diversification helps manage volatility and mitigates losses due to sudden downward changes in the market, it can prevent Tamarack from fully capitalizing on short term market gains. Despite a lower realized price in the quarter versus the benchmark, the full year effect of the Company's strategy had a positive financial impact. Tamarack's exposure to diversified gas markets is expected to continue providing meaningful benefit through both risk mitigation and improvements in realized pricing over the long-term.

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

<b>Natural Gas Market</b>	<b>Percentage Exposure (as at December 31, 2019)</b>
NYMEX (Physical Basis Swap)	27.2
AECO Daily (5A)	18.8
Waddington	18.0
Malin	14.4
Dawn	7.2
Chicago	7.2
Michigan City Gate	7.2
Fixed Price	0.0
AECO Daily (5A) + premium (SK)	0.0
	100%

Oversupply and takeaway capacity restrictions have continued to create downward pricing pressure and volatility in Alberta natural gas markets. Despite some improvement and stabilization in AECO prices as a result of recently approved regulatory changes, Tamarack anticipates challenging market conditions will persist for the long term. The Company continues to benefit from multiple third-party gas sales contracts featuring various end dates until 2022. These contracts provide diversification of the Company's natural gas price exposure and help mitigate individual market volatility risk. Through the fourth quarter of 2019, more than 80% of Tamarack's total natural gas production was priced at alternate markets to AECO, including Malin, Chicago, Michigan Consolidated, Dawn, Waddington, Emerson and NYMEX. Pricing in these markets is contracted as daily index pricing less transportation tolls or as 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			Years ended		
	December 31,			December 31,		
	2019	2018	% change	2019	2018	% change
Revenue (\$ thousands)						
Oil and NGL	<b>\$86,398</b>	\$55,962	54	<b>\$340,835</b>	\$355,826	(4)
Natural gas	<b>11,301</b>	17,113	(34)	<b>40,231</b>	42,978	(6)
Total	<b>\$97,699</b>	\$73,075	34	<b>\$381,066</b>	\$398,804	(4)
Average realized price:						
Light oil (\$/bbl)	<b>64.26</b>	36.78	75	<b>66.25</b>	64.17	3
Heavy oil (\$/bbl)	<b>58.96</b>	49.33	20	<b>55.27</b>	59.13	(7)
Natural gas liquids (\$/bbl)	<b>21.96</b>	33.72	(35)	<b>25.57</b>	41.89	(39)
Combined average oil and NGL (\$/boe)	<b>59.51</b>	37.08	60	<b>61.58</b>	62.02	(1)
Natural gas (\$/mcf)	<b>2.26</b>	3.70	(39)	<b>2.06</b>	2.30	(10)
Revenue (\$/boe)	<b>42.72</b>	32.05	33	<b>43.37</b>	45.08	(4)
Benchmark pricing:						
West Texas Intermediate (US\$/bbl)	<b>56.91</b>	58.79	(3)	<b>57.02</b>	64.78	(12)
Edmonton Par (Cdn\$/bbl)	<b>66.86</b>	48.26	39	<b>69.76</b>	69.14	1
Hardisty Heavy (Cdn\$/bbl)	<b>50.06</b>	34.23	46	<b>60.13</b>	49.95	20
NYMEX monthly settlement (US\$/mmbtu)	<b>2.62</b>	3.83	(32)	<b>2.78</b>	3.24	(14)
AECO daily index (Cdn\$/mcf)	<b>2.46</b>	1.55	59	<b>1.51</b>	1.49	1
AECO monthly index (Cdn\$/mcf)	<b>2.32</b>	1.89	23	<b>1.37</b>	1.52	(10)

Revenue per boe from oil, natural gas and NGL sales for Q4 2019 increased by 34% compared to the same period in 2018, primarily due to the increase in crude oil prices, partially offset by lower NGL and natural gas prices compared to the same period of the prior year.

For the year ended December 31, 2019 revenue per boe from oil, natural gas and NGL sales decreased by 4% compared to the same period in 2018, primarily due to the decrease in NGL and natural gas prices.

The Company may use both financial derivatives and physical delivery contracts to manage fluctuations in commodity prices, foreign exchange rates and interest rates. All such transactions are conducted within risk management tolerances that are reviewed quarterly by Tamarack's Board of Directors. At December 31, 2019, the Company held derivative commodity, foreign exchange and interest rate contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	4,000 bbls/day	January 1, 2020 – March 31, 2020	WTI fixed price	US \$60.78
Crude oil	2,700 bbls/day	April 1, 2020 – June 30, 2020	WTI fixed price	US \$58.27
Crude oil	7,000 bbls/day	January 1, 2020 – December 31, 2020	WTI/Edm par differential	US (\$7.54)
Foreign exchange	1,000,000 US\$/mth	January 1, 2020 – March 31, 2020	Exchange rate	Cdn \$1.3405
Interest rate	25,000,000 US\$/mth	January 1, 2020 – April 24, 2023	Fixed rate	1.90%
Interest rate	25,000,000 US\$/mth	January 1, 2020 – June 14, 2023	Fixed rate	1.75%

At December 31, 2019, the commodity, foreign exchange and interest rate contracts were fair valued with a liability of \$4.1 million (December 31, 2018 - \$19.7 million asset) recorded on the balance sheet and an unrealized loss of \$23.7 million recorded in earnings for the year ended December 31, 2019 (December 31, 2018 - \$27.1 million unrealized gain).

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

At December 31, 2019, the Company held the following physical commodity contracts:

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	7,901 GJ/day	January 1, 2020 – January 31, 2020	AECO fixed price	Cdn \$2.64
Natural gas	2,320 GJ/day	February 1, 2020 – February 29, 2020	AECO fixed price	Cdn \$2.30
Natural gas	15,000 mmbtu/day	February 1, 2020 – February 29, 2020	AECO/Henry Hub differential	Index – US \$0.56
Natural gas	5,000 GJ/day	March 1, 2020 – March 31, 2020	AECO fixed price	Cdn \$2.45
Natural gas	15,000 mmbtu/day	March 1, 2020 – March 31, 2020	AECO/Henry Hub differential	Index – US \$1.16
Natural gas	15,000 mmbtu/day	April 1, 2020 – October 31, 2020	AECO/Henry Hub differential	Index – US \$1.23

Since December 31, 2019, the Company adjusted its derivative portfolio by entering into a transaction that cancelled a portion of existing derivative contracts and re-entered into new derivative contracts. As at March 4, 2020, the Company held derivative commodity, foreign exchange and interest rate contracts as follows:

Subject contract	Quantity	Term	Hedge type	Strike price
Crude oil	1,000 bbls/day	March 4, 2020 – March 31, 2020	WTI fixed price	US \$59.86
Crude oil	500 bbls/day	April 1, 2020 – June 30, 2020	WTI fixed price	US \$59.17
Crude oil	3,000 bbls/day	July 1, 2020 – September 30, 2020	WTI fixed price	US \$54.57
Crude oil	3,000 bbls/day	October 1, 2020 – December 31, 2020	WTI fixed price *	US \$54.57
Crude oil	5,650 bbls/day	March 4, 2020 – March 31, 2020	WTI Put	US \$58.00
Crude oil	4,400 bbls/day	April 1, 2020 – June 30, 2020	WTI Put	US \$58.00
Crude oil	1,700 bbls/day	July 1, 2020 – September 30, 2020	WTI Put	US \$58.00
Crude oil	7,000 bbls/day	March 4, 2020 – December 31, 2020	WTI/Edm par differential	US (\$7.54)
Foreign exchange	1,000,000 US\$/mth	March 4, 2020 – March 31, 2020	Exchange rate	Cdn \$1.3405
Foreign exchange	3,000,000 US\$/mth	April 1, 2020 – June 30, 2020	Exchange rate	Cdn \$1.3271
Interest rate	25,000,000 US\$/mth	March 4, 2020 – April 24, 2023	Fixed rate	1.90%
Interest rate	25,000,000 US\$/mth	March 4, 2020 – June 14, 2023	Fixed rate	1.75%

\* Extendable for an additional six months at the counter-parties discretion.

Since December 31, 2019, the Company has not entered into any additional physical contracts.

## **Royalties**

### **Quarter-over-Quarter**

	Q4 2019	Q3 2019	% change
Royalty expenses (\$ thousands)	<b>\$10,041</b>	\$9,691	4
\$/boe	<b>4.39</b>	4.36	1
percent of sales	<b>10</b>	11	(9)

Royalties as a percentage of revenue were comparable in Q4/19 relative to Q3/19.

## Year-over-Year

	Three months ended			Years ended		
	December 31,			December 31,		
	2019	2018	% change	2019	2018	% change
Royalty expenses (\$ thousands)	<b>\$10,041</b>	\$5,902	70	<b>\$39,060</b>	\$39,901	(2)
\$/boe	<b>4.39</b>	2.59	69	<b>4.45</b>	4.51	(1)
percent of sales	<b>10</b>	8	25	<b>10</b>	10	–

Royalties as a percentage of revenue for the three months ended December 31, 2019 were higher than the same period in 2018, which was due to the sliding scale nature of some oil royalties which lowers the percentage paid during periods of low oil prices, which was the case during Q4/18. The Company expects royalty rates as a percentage of revenue to remain in the 10% to 12% range for 2020 based on current forecast commodity price levels.

Royalties as a percentage of revenue for the year ended December 31, 2019 were comparable to the same period in 2018.

## Net Production and Transportation Expenses

### Quarter-over-Quarter

(\$ thousands, except per boe)	Q4 2019	Q3 2019	% change
Production and transportation expenses	<b>\$23,212</b>	\$22,901	1
Less: processing income	<b>431</b>	963	(55)
Total net production and transportation expenses	<b>\$22,781</b>	\$21,938	4
Total (\$/boe)	<b>\$9.96</b>	\$9.87	1

Net production and transportation expenses in Q4/19 were 1% higher at \$9.96/boe compared to \$9.87/boe in Q3/19, primarily due to start-up costs for the new wells brought on-stream during the quarter, which led to higher net production and transportation expenses per boe.

### Year-over-Year

(\$ thousands, except per boe)	Three months ended			Years ended		
	December 31,			December 31,		
	2019	2018 <sup>(1)</sup>	% change	2019	2018 <sup>(1)</sup>	% change
Production and transportation expenses	<b>\$23,212</b>	\$24,291	(4)	<b>\$89,897</b>	\$93,683	(4)
Less: processing income	<b>431</b>	426	1	<b>1,750</b>	658	166
Total net production and transportation expenses	<b>\$22,781</b>	\$23,865	(5)	<b>\$88,147</b>	\$93,025	(5)
Total (\$/boe)	<b>\$9.96</b>	\$10.47	(5)	<b>\$10.03</b>	\$10.52	(5)

<sup>(1)</sup> IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

For the three months and year ended December 31, 2019, net production and transportation expenses per boe were lower compared to the same periods in 2018. This resulted from several factors, including the net impact of reduced transportation costs in the Veteran area as a result of a commissioned oil sales pipeline which eliminated the trucking of sales oil in late Q4/18, the Company adopting IFRS 16, "Leases" ("IFRS 16") in 2019 and an increase in production volumes in the Veteran area, where production expenses are generally lower than the corporate average.

## **Operating Netback**

### **Quarter-over-Quarter**

(\$/boe)	Q4 2019	Q3 2019	%
			change
Average realized sales	<b>\$42.72</b>	\$40.28	6
Royalty expenses	<b>(4.39)</b>	(4.36)	1
Net production and transportation expenses	<b>(9.96)</b>	(9.87)	1
Operating field netback	<b>28.37</b>	26.05	9
Realized commodity hedging loss	<b>(2.04)</b>	(1.55)	32
Operating netback	<b>\$26.33</b>	\$24.50	7

The Company's operating netback (see "Non-IFRS Measures") increased 7% in Q4/19 compared to Q3/19. This was primarily due to a higher realized price for natural gas compared to the previous quarter.

### **Year-over-Year**

(\$/boe)	Three months ended			Years ended		
	December 31,			December 31,		
	2019	2018 <sup>(1)</sup>	%	2019	2018 <sup>(1)</sup>	%
			change			change
Average realized sales	<b>\$42.72</b>	\$32.05	33	<b>\$43.37</b>	\$45.08	(4)
Royalty expenses	<b>(4.39)</b>	(2.59)	69	<b>(4.45)</b>	(4.51)	(1)
Net production and transportation expenses	<b>(9.96)</b>	(10.47)	(5)	<b>(10.03)</b>	(10.52)	(5)
Operating field netback	<b>28.37</b>	18.99	49	<b>28.89</b>	30.05	(4)
Realized commodity hedging gain (loss)	<b>(2.04)</b>	0.04	(5,200)	<b>(1.42)</b>	(2.03)	(30)
Operating netback	<b>\$26.33</b>	\$19.03	38	<b>\$27.47</b>	\$28.02	(2)

<sup>(1)</sup> IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

For the three months ended December 31, 2019, operating netbacks were higher than the same period in 2018 due to higher realized oil prices in 2019, partially offset by a realized hedging loss in 2019 and lower NGL and natural gas prices in Q4/19 relative to Q4/18.

For the year ended December 31, 2019, operating netbacks were lower than the same period in 2018 due to lower natural gas prices in 2019 partially offset by lower net production and transportation expense in 2019.

## General and Administrative (“G&A”) Expenses

### Quarter-over-Quarter

(\$ thousands, except per boe)	Q4 2019	Q3 2019	% change
Gross costs	\$4,290	\$4,091	5
Capitalized costs and recoveries	(992)	(1,003)	(1)
General and administrative costs	\$3,298	\$3,088	7
Total (\$/boe)	\$1.44	\$1.39	4

Gross and net G&A expenses for the fourth and third quarters of 2019 were comparable. G&A expenses on a per boe basis remained consistent quarter-over-quarter.

### Year-over-Year

(\$ thousands, except per boe)	Three months ended			Years ended		
	December 31,			December 31,		
	2019	2018	% change	2019	2018	% change
Gross costs	\$4,290	\$4,272	–	\$16,306	\$17,064	(4)
Capitalized costs and recoveries	(992)	(934)	6	(3,842)	(3,678)	4
General and administrative costs	\$3,298	\$3,338	(1)	\$12,464	\$13,386	(7)
Total (\$/boe)	\$1.44	\$1.46	(1)	\$1.42	\$1.51	(6)

Gross and net G&A costs decreased for the three months and year ended December 31, 2019, compared to the same periods in 2018, due to a continued focus on cutting non-essential G&A costs. On a per boe basis, net G&A costs for the three months and year ended December 31, 2019 were lower than the same periods in 2018 due to lower absolute gross and net G&A expenses.

## Stock-Based Compensation Expense

### Quarter-over-Quarter

(\$ thousands, except per boe)	Q4 2019	Q3 2019	% change
Gross costs	\$3,594	\$3,616	(1)
Capitalized costs	(612)	(628)	(3)
Total stock-based compensation	\$2,982	\$2,988	–
Total (\$/boe)	\$1.30	\$1.34	(3)

Stock-based compensation expense related to stock options (“Options”), restricted share units (“RSUs”) and performance share units (“PSUs”) was similar in Q4/19 compared to Q3/19. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

### Year-over-Year

(\$ thousands, except per boe)	Three months ended			Years ended		
	December 31,			December 31,		
	2019	2018	% change	2019	2018	% change
Gross costs	\$3,594	\$4,040	(11)	\$12,073	\$12,471	(3)
Capitalized costs	(612)	(1,140)	(46)	(2,384)	(3,598)	(34)
Total stock-based compensation	\$2,982	\$2,900	3	\$9,689	\$8,873	9
Total (\$/boe)	\$1.30	\$1.27	2	\$1.10	\$1.00	10

Stock-based compensation expense related to Options, RSUs and PSUs for the three months and year ended December 31, 2019 was higher compared to the same periods in 2018 due to additional Options, RSUs and PSUs that were issued late in Q1/19. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

During the year ended December 31, 2019, the Company issued 0.4 million Options (at a weighted average exercise price of \$2.57 per share), 2.5 million RSUs and 1.2 million PSUs compared to 0.2 million Options (at a weighted average exercise price of \$2.62 per share), 2.4 million RSUs and 1.0 million PSUs during the same period in 2018.

## **Interest Expense**

<b>Quarter-over-Quarter</b>			
(\$ thousands, except per boe)	<b>Q4 2019</b>	Q3 2019	% change
Interest on bank debt	<b>\$1,938</b>	\$1,890	3
Fees associated with credit facility renewal	<b>8</b>	(13)	(162)
Interest on lease liabilities	<b>234</b>	243	(4)
Total interest expense	<b>\$2,180</b>	\$2,120	3
Total (\$/boe)	<b>\$0.95</b>	\$0.95	–
Average drawings on bank debt	<b>\$198,887</b>	\$182,075	9

Interest expense was higher in Q4/19 compared to the previous quarter due to a higher average amount drawn quarter-over-quarter on the revolving credit facility.

## **Year-over-Year**

(\$ thousands, except per boe)	Three months ended			Years ended		
	December 31,			December 31,		
	<b>2019</b>	2018 <sup>(1)</sup>	% change	<b>2019</b>	2018 <sup>(1)</sup>	% change
Interest on bank debt	<b>\$1,938</b>	\$1,706	14	<b>\$7,573</b>	\$7,681	(1)
Fees associated with credit facility renewal	<b>8</b>	–	–	<b>631</b>	391	61
Interest on lease liabilities	<b>234</b>	–	–	<b>1,241</b>	–	–
Total interest expense	<b>\$2,180</b>	\$1,706	28	<b>\$9,445</b>	\$8,072	17
Total (\$/boe)	<b>\$0.95</b>	\$0.75	27	<b>\$1.07</b>	\$0.91	18
Average drawings on bank debt	<b>\$198,887</b>	\$159,286	25	<b>\$187,575</b>	\$158,898	18

<sup>(2)</sup> IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

Interest expense for the three months and year ended December 31, 2019 was higher than the same periods in 2018 due to the Company adopting IFRS 16 in 2019 and the higher average drawings on the revolving credit facility, offset by increased utilization of lower interest rate options that were available through the Company's syndicate of lenders.

## **Depletion, Depreciation, Amortization and Accretion (“DDA&A”)**

The Company depletes its property, plant and equipment (“PP&E”) based on its proved plus probable reserves. Right-of-use (“ROU”) assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the underlying asset or the lease term. If the lease transfers ownership of the underlying asset to the Company at the end of the lease term, or the Company is reasonably certain it will exercise its purchase option, Tamarack depletes its ROU assets 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 2019	Q3 2019	% change
Depletion and depreciation	\$43,172	\$42,483	2
Amortization of undeveloped leases	266	266	–
Accretion	954	950	–
<b>Total</b>	<b>\$44,392</b>	<b>\$43,699</b>	<b>2</b>
Depletion and depreciation (\$/boe)	\$18.88	\$19.10	(1)
Amortization (\$/boe)	0.12	0.12	–
Accretion (\$/boe)	0.42	0.43	(2)
<b>Total (\$/boe)</b>	<b>\$19.42</b>	<b>\$19.65</b>	<b>(1)</b>

DDA&A expense per boe and on an absolute basis for the fourth and third quarters of 2019 were comparable with a slight decrease in the DDA&A expense per boe. The decrease was due to the completion of the Company’s December 31, 2019 independent reserves evaluation which resulted in an increase in Tamarack’s overall reserve base.

### Year-over-Year

(\$ thousands, except per boe)	Three months ended			Years ended		
	December 31,			December 31,		
	2019	2018 <sup>(1)</sup>	% change	2019	2018 <sup>(1)</sup>	% change
Depletion and depreciation	\$43,172	\$44,498	(3)	\$166,312	\$176,498	(6)
Amortization of undeveloped leases	266	328	(19)	999	1,078	(7)
Accretion	954	1,043	(9)	4,075	4,106	(1)
<b>Total</b>	<b>\$44,392</b>	<b>\$45,869</b>	<b>(3)</b>	<b>\$171,386</b>	<b>\$181,682</b>	<b>(6)</b>
Depletion and depreciation (\$/boe)	\$18.88	\$19.52	(3)	\$18.93	\$19.95	(5)
Amortization (\$/boe)	0.12	0.14	(14)	0.11	0.12	(8)
Accretion (\$/boe)	0.42	0.46	(9)	0.46	0.46	–
<b>Total (\$/boe)</b>	<b>\$19.42</b>	<b>\$20.12</b>	<b>(3)</b>	<b>\$19.50</b>	<b>\$20.53</b>	<b>(5)</b>

<sup>(1)</sup> IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

For the three months and year ended December 31, 2019, DDA&A expense per boe was lower relative to the same periods in 2018. The decrease was due to the completion of the Company’s December 31, 2019 independent reserves evaluation which resulted in an increase in Tamarack’s overall reserve base following the successful 2019 drilling program, better-than-expected well performance, additional reserves being added as a result of the Veteran waterflood project and a net impairment taken in the fourth quarter of 2018. On an absolute basis, DDA&A expense was lower for both the three months and year ended December 31, 2019 due to the lower DDA&A expense per boe.

## **Impairment**

Impairment of \$68.0 million was recorded as at December 31, 2019 as a result of a decrease in current and forecast future natural gas and NGL prices. The impairment recognized relates to the Company's Cardium cash-generating unit ("CGU") that includes associated natural gas produced with the Cardium oil and also includes Mannville gas wells and a Pekisko gas unit. The recoverable amount of this CGU as at December 31, 2019 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 10% to 20% (level 3 inputs). The recoverable amount of the Cardium CGU was determined using the fair value less costs of disposal methodology. This methodology is based on what Tamarack could receive should these assets be disposed in the current environment taking into account lower natural gas and NGL prices.

## **Income Taxes**

The Company did not incur any cash tax expense for the three months and year ended December 31, 2019 and does not expect to pay any cash tax until 2023 or later based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

The Company has incorporated the Alberta corporate income tax rate reductions enacted by the Government of Alberta for the periods from July 1, 2019 to January 1, 2022, which reduced the provincial income tax rate to 11% effective July 1, 2019 and will further reduce the rate by an additional 1% on January 1 for each of the years 2020, 2021 and 2022, bringing the rate to 8%. The deferred income tax recovery includes \$4.3 million attributable to these tax rate decreases.

For the three months and year ended December 31, 2019, a deferred income tax recovery of \$11.5 million and \$14.4 million were recognized, respectively, compared to a deferred income tax expense of \$11.5 million and \$20.8 million for the same periods in 2018.

The following table outlines the Company's estimated tax pools as at December 31, 2019:

Tax Pool Category	Deduction Rate	(\$ millions)
Canadian exploration expense (CEE)	100%	31
Canadian development expense (CDE)	30%	315
Canadian oil and gas property expense (COGPE)	10%	210
Non-capital losses (NCL)	100%	166
Undepreciated capital cost (UCC)	25%	136
Share issue costs and other	various	1
Total		859

## Adjusted Funds Flow and Net Income (Loss)

<b>Quarter-over-Quarter</b>			
(\$ thousands, except per share)	<b>Q4 2019</b>	Q3 2019	%
			change
Income (loss) before taxes	<b>\$(62,028)</b>	\$782	(8,032)
Depletion, depreciation and amortization	<b>43,438</b>	42,749	2
Stock-based compensation	<b>2,982</b>	2,988	–
Gain on disposition of property, plant and equipment	<b>(27)</b>	–	–
Accretion expense on decommissioning obligations	<b>954</b>	950	–
Unrealized loss on financial instruments	<b>1,374</b>	1,814	(24)
Unrealized gain on foreign exchange	<b>(2,859)</b>	–	–
Unrealized loss on cross-currency swaps	<b>2,908</b>	–	–
Impairment of property, plant and equipment	<b>68,000</b>	–	–
Adjusted funds flow	<b>\$54,742</b>	\$49,283	11
Per share - basic	<b>\$0.25</b>	\$0.22	14
Per share - diluted	<b>\$0.25</b>	\$0.22	14
Net loss	<b>\$(50,546)</b>	\$(111)	45,437
Per share - basic	<b>\$(0.23)</b>	\$(0.00)	–
Per share - diluted	<b>\$(0.23)</b>	\$(0.00)	–

The adjusted funds flow (see “Non-IFRS Measures”) generated during Q4/19 was higher than in Q3/19 primarily due to a 6% increase in realized commodity prices.

The Company recorded a net loss of \$50.5 million (\$0.23 per share basic and diluted) during the three months ended December 31, 2019, compared to a net loss of \$0.1 million (\$0.00 per share basic and diluted) during the previous quarter. This was primarily due to an impairment to property, plant and equipment taken in Q4/19, partially offset by a 6% increase in realized commodity prices in Q4/19 and a deferred income tax recovery in Q4/19.

## Year-over-Year

(\$ thousands, except per boe)	Three months ended			Years ended		
	December 31,			December 31,		
	2019	2018 <sup>(1)</sup>	% change	2019	2018 <sup>(1)</sup>	% change
Income (loss) before taxes	<b>\$(62,028)</b>	\$30,415	(304)	<b>\$(53,409)</b>	\$59,142	(190)
Depletion, depreciation and amortization	<b>43,438</b>	44,826	(3)	<b>167,311</b>	177,576	(6)
Stock-based compensation	<b>2,982</b>	2,900	3	<b>9,689</b>	8,873	9
Gain on disposition of property, plant and equipment	<b>(27)</b>	(1,079)	(97)	<b>(27)</b>	(1,085)	(98)
Accretion expense on decommissioning obligations	<b>954</b>	1,043	(9)	<b>4,075</b>	4,106	(1)
Unrealized loss (gain) on financial instruments	<b>1,374</b>	(44,759)	(103)	<b>23,746</b>	(27,137)	(188)
Unrealized gain on foreign exchange	<b>(2,859)</b>	–	–	<b>(2,859)</b>	–	–
Unrealized loss on cross-currency swaps	<b>2,908</b>	–	–	<b>2,908</b>	–	–
Impairment of property, plant and equipment	<b>68,000</b>	5,000	1,260	<b>68,000</b>	5,000	1,260
Adjusted funds flow	<b>\$54,742</b>	\$38,346	43	<b>\$219,434</b>	\$226,475	(3)
Per share - basic	<b>\$0.25</b>	\$0.17	47	<b>\$0.97</b>	\$0.99	(2)
Per share - diluted	<b>\$0.25</b>	\$0.17	47	<b>\$0.97</b>	\$0.97	–
Net income (loss)	<b>\$(50,546)</b>	\$18,952	(367)	<b>\$(39,011)</b>	\$38,310	(202)
Per share - basic	<b>\$(0.23)</b>	\$0.08	(388)	<b>\$(0.17)</b>	\$0.17	(200)
Per share - diluted	<b>\$(0.23)</b>	\$0.08	(388)	<b>\$(0.17)</b>	\$0.16	(206)

<sup>(1)</sup> IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

The adjusted funds flow (see “Non-IFRS Measures”) for the three months ended December 31, 2019 was higher compared to the same period of 2018. This was primarily due to a 33% increase in realized commodity prices in Q4/19.

The adjusted funds flow (see “Non-IFRS Measures”) for the year ended December 31, 2019 was lower than in the same period of 2018. This was primarily due to a 4% decrease in realized commodity prices in 2019.

The Company recorded a net loss of \$50.5 million (\$0.23 per share basic and diluted) and \$39.0 million (\$0.17 per share basic and diluted), respectively, during the three months and year ended December 31, 2019, compared to 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) for the same periods in 2018.

## **Capital Expenditures (Including Exploration and Evaluation Expenditures)**

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

(\$ thousands)	Three months ended			Years ended		
	December 31,			December 31,		
	2019	2018	% change	2019	2018	% change
Land	\$1,090	\$42	2,495	\$1,603	\$4,690	(66)
Geological and geophysical	74	–	–	198	13	1,423
Drilling and completion	16,251	15,254	7	129,344	167,216	(23)
Equipment and facilities	4,646	9,664	(52)	44,378	51,254	(13)
Capitalized G&A	807	791	2	3,033	2,861	6
Office equipment	86	47	83	410	217	89
Total capital expenditures	\$22,954	\$25,798	(11)	\$178,966	\$226,251	(21)

During the fourth quarter of 2019, the Company drilled, completed and equipped 15 (14.6 net) Viking oil wells. In addition to the fourth quarter drilling program, the Company also completed and brought on production 11.0 net Viking oil wells that were drilled in late Q3/19.

Tamarack also directed capital to the continued development of a waterflood program in the Company's Veteran, Alberta area with the conversion of 6 (5.9 net) Viking oil wells into water injectors. The waterflood project is designed to improve oil recoveries, reduce corporate decline rates and increase production rates while utilizing Tamarack's existing and owned infrastructure. These supplementary projects are subject to the same rate of return thresholds as those used for development drilling when competing for capital.

For the year ended December 31, 2019

### Drilling Summary

	<u>Gross</u>	<u>Net</u>
Viking	127.0	124.1
Cardium	14.0	12.5
Penny	2.0	2.0
Water source and injectors	6.0	5.9
	149.0	144.5

As at December 31, 2019, the Company's net undeveloped land totaled 496,441 acres.

## **Property Acquisitions**

During the year ended December 31, 2019, the Company completed a total of six tuck-in acquisitions for \$9.9 million, adding 17.9 net sections of undeveloped Viking land adjacent to Tamarack's existing acreage in the Veteran/Consort area, 0.6 net sections in the Wilson Creek/Alder Flats area and approximately 800 boe/d of associated production.

## **Share Capital**

At December 31, 2019, Tamarack had issued and outstanding 222,793,117 Common Shares ("Common Shares"), net of 469,120 Common Shares which were held in treasury, 2,193,333 Options, 6,986,921 RSUs and 2,156,980 PSUs. At March 4, 2020, Tamarack has issued and outstanding 222,295,253 Common Shares, of which 302,884 are held in treasury, 1,942,333 Options, 6,403,019 RSUs and 2,166,980 PSUs. This compares to December 31, 2018, at which time Tamarack had issued and outstanding 226,072,693 Common Shares, of which 1,193,188 were held in treasury, 2,944,833 Options, 7,407,472 RSUs and 983,000 PSUs. No preferred shares of Tamarack are issued and outstanding.

At December 31, 2019, Tamarack Acquisition Corp. had 1,021,974 preferred shares (“TAC Preferred Shares”) issued and outstanding (December 31, 2018 - 1,086,974). The TAC Preferred Shares were fully vested and exchangeable into 982,667 Common Shares (December 31, 2018 - 1,045,168) of Tamarack at an exchange price of \$3.12 per Common Share.

At March 4, 2020, Tamarack Acquisition Corp. had 740,307 preferred shares (“TAC Preferred Shares”) issued and outstanding. The TAC Preferred Shares were fully vested and exchangeable into 711,834 Common Shares of Tamarack at an exchange price of \$3.12 per Common Share.

As noted under “Liquidity and Capital Resources” below, during the year ended December 31, 2019, Tamarack purchased and cancelled 4,181,100 outstanding Common Shares under its normal course issuer bid (“NCIB”) program, for a total investment of \$8.3 million. This compared to the year ended December 31, 2018, when Tamarack purchased and cancelled 3,025,000 outstanding Common Shares under its NCIB program, for a total investment of \$11.7 million. The NCIB program 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 program also helps to offset the dilutive impact that may be associated with the exercise and settlement of Options, RSUs and PSUs issued under Tamarack’s stock-based compensation programs.

### **Liquidity and Capital Resources**

(\$ thousands)	<b>December 31, 2019</b>	December 31, 2018 <sup>(1)</sup>	September 30, 2019
Working capital deficiency (surplus)	<b>\$(3,426)</b>	\$18,385	\$14,169
Bank debt	<b>192,907</b>	161,495	198,971
Net debt	<b>189,481</b>	179,880	213,140
Quarterly adjusted funds flow	<b>\$54,742</b>	\$38,346	\$49,283
Annualized factor	<b>4</b>	4	4
Annualized adjusted funds flow	<b>218,968</b>	153,384	197,132
Net debt to annualized adjusted funds flow	<b>0.9x</b>	1.2x	1.1x

<sup>(1)</sup> IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

Tamarack’s net debt (see “Non-IFRS Measures”), including working capital deficiency and the fair value of cross-currency swaps but excluding the fair value of financial instruments and lease liabilities, totaled \$189.5 million as at December 31, 2019. This compares to its net debt of \$213.1 million and \$179.9 million in Q3/19 and Q4/18, respectively. Tamarack’s Q4/19 net debt to annualized adjusted funds flow ratio (see “Non-IFRS Measures”) was 0.9 times.

The Company’s \$23.2 million investment in capital expenditures and property acquisitions during Q4/19 was funded entirely by Tamarack’s adjusted funds flow (see “Non-IFRS Measures”) of \$54.7 million. Tamarack net debt levels decreased \$23.7 million during Q4/19 due to the planned reduction in capital expenditures.

With continued commodity price volatility, 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, enhancing production 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 program through the facilities of the Toronto Stock Exchange and alternate trading platforms, pursuant to which the Company has the option to purchase its Common Shares for cancellation, thereby reducing the total number of shares outstanding. The NCIB program represents an additional tool that can be employed as part of management's ongoing strategy to increase long-term shareholder value. For the year ended December 31, 2019, the Company spent \$8.3 million to purchase and cancel 4,181,100 outstanding Common Shares under the NCIB program. Subsequent to the end of the year, the Company purchased an additional 664,100 outstanding Common Shares under the NCIB program for \$1.3 million.

Over and above the NCIB program, during the fourth quarter of 2019, the Company also directed \$1.1 million to purchase 592,199 issued and outstanding Common Shares in the open market. Once purchased, these Common Shares are held in trust by Tamarack's trustee and used to settle RSUs upon future exercises. This practice mitigates dilution by eliminating the need to issue new Common Shares from treasury for the settlement of RSUs and PSUs. Instead, Tamarack has the ability, when needed, to 'draw down' from the remaining balance of purchased Common Shares that are held in trust to settle RSU exercises, further supporting Tamarack's per share metrics. At December 31, 2019, the remaining balance of purchased Common Shares held in trust totaled 469,120.

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 \$320 million and a \$30 million operating facility (collectively, the "Facility") with a syndicate of lenders. The Facility totals \$350 million, of which \$192.9 million was drawn as of December 31, 2019 (December 31, 2018 - \$161.5 million), lasts for a 365-day period and will be subject to its next 365-day extension by May 31, 2020. If not extended on May 31, 2020, the Facility will cease to revolve and all outstanding balances will become repayable one year from that date.

The Facility includes an accordion feature which allows Tamarack to increase the revolving credit facility portion 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, 2019, the accordion feature had 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 that Tamarack employs will vary from time to time based on capital needs and current market rates. As at December 31, 2019, 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 lenders' interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review by the syndicate of lenders is scheduled to be completed by May 31, 2020.

There are no financial covenants governing the Facility.

## **Guidance**

Tamarack's average annual production for 2019 of 24,072 boe/d was in line with guidance of 23,500 to 24,500 boe/d (oil and NGL weighting of 63% to 65%).

Over the past several years, Tamarack has maintained a disciplined capital allocation strategy designed to achieve sustainability through environments of weak and volatile oil prices, while continuing to direct excess adjusted funds flow to purchase its Common Shares under its normal course issuer bid ("NCIB") program. During the 12 months ended December 31, 2019, Tamarack invested \$8.3 million to purchase and cancel 4,181,100 Common Shares. In addition, the Company further invested \$3.5 million to purchase an additional 1,639,764 Common Shares to be held in trust by Tamarack's trustee and used to settle RSUs upon future exercises, offsetting future RSUs dilution and supporting debt-adjusted per share growth (see "Non-IFRS Measures").

Tamarack's 2020 budget of \$170 to \$180 million is forecast to drive average production volumes consistent with 2019 guidance levels, ranging from 23,500 to 24,500 boe/d, and is expected to be funded entirely by the Company's adjusted funds flow. The program is focused on increasing oil and liquids weightings at year end 2020. This positive impact is a direct result of slowing down the Company's corporate oil decline rate due to an increasing anticipated response from the waterflood development at Veteran, which will continue to enhance Tamarack's longer-term sustainability.

The 2020 capital budget of \$170 to \$180 million includes maintenance capital estimated to range between \$112 and \$115 million which is designed to keep production flat, while approximately \$50 to \$58 million has been earmarked for Viking waterflood development projects, anticipated to positively impact decline rates and production later in 2020 and into 2021. In addition, Tamarack plans to direct between \$5 and \$8 million to expenditures for land and seismic, approximately \$3 million for abandonment projects, and \$2 to \$3 million in initiatives designed to reduce emissions as part of the Company's ongoing commitment to its environmental, social and governance responsibilities. Tamarack's 2020 capital program assumes a decrease in corporate declines from 38% in 2019 to 34% in 2020, with corporate declines expected to fall below 30% in 2021 as a result of the positive response from ongoing waterflood development.

Tamarack's 2020 maintenance capital budget anticipates the drilling of 90 to 100 net wells, including 80 to 90 Viking light oil wells, seven to nine Cardium light oil wells and two to five wells at Penny targeting the Lower Mississippian development. The Company's \$50 to \$58 million of planned waterflood investment in 2020 is expected to include 14 to 16 well conversions in 2020 and the drilling of 15 to 20 additional injection wells at East Veteran.

Tamarack's 2020 capital program will be fully funded by adjusted funds flow at current strip prices. Adjusted funds flow that are generated above capital expenditures will be directed 50% to the purchase of shares for cancellation through the NCIB program and to offset future RSU dilution, with the remaining 50% directed towards debt repayment or continued accretive tuck-in acquisitions.

**The Company's 2020 budget is summarized in the following table:**

	<b>2020 Budget</b>
Average annual production (boe/d)	23,500 – 24,500
Oil and NGL weighting (%)	~64 – 66
Exit production (boe/d)	23,500 – 24,500
Oil weighting (%)	~59 – 62
Oil and NGL weighting (%)	~65 – 68
2020 Capital expenditures, excluding acquisitions (\$millions)	\$170 – 180

This budget has been designed to optimize returns, allowing Tamarack to enhance per share metrics and fully fund its capital expenditure program. This budget reflects the continued volatility in equity markets, uncertainty of future oil pricing given backwardation of the forward curve, as well as the uncertain prognosis for additional pipeline takeaway capacity from western Canada. In light of management's belief that the Company's prevailing share price does not adequately reflect the underlying value of its assets, Tamarack intends to continue to purchase shares through its NCIB program even if commodity prices remain low.

Should forecasted realized commodity prices significantly fluctuate, Tamarack maintains control to accelerate or reduce capital expenditures, redirect capital to purchase shares through the NCIB program or pay down debt.

**Commitments**

On January 1, 2019, the Company adopted IFRS 16 which resulted in the recognition of lease liabilities related to operating leases for facilities on the balance sheet. These liabilities were previously reported as commitments. The following table summarizes the Company's commitments as at December 31, 2019:

(\$ thousands)	2020	2021	2022	2023	2024	2025+
Bank debt	–	192,907	–	–	–	–
Office lease <sup>(1)</sup>	263	–	–	–	–	–
Take or pay commitments <sup>(2)</sup>	2,256	2,294	2,340	2,396	–	–
Gas transportation <sup>(3)</sup>	229	76	–	–	–	–
Total	2,748	195,277	2,340	2,396	–	–

(1) Relates to the operating costs for the office lease which are a non-lease component of lease liabilities.

(2) Pipeline commitment to deliver a minimum of 636 m<sup>3</sup>/d of crude oil/condensate subject to a take-or-pay provision of \$9.00/m<sup>3</sup>. The term starts on January 1, 2019 and lasts for 60 months.

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

Rental fees, which were in the December 31, 2018 commitments table, were removed due to the adoption of IFRS 16. The amounts removed were as follows:

(\$ thousands)	2019	2020	2021	2022	2023	2024	2025+
Rental fee	6,312	6,312	6,312	4,441	2,570	1,142	1,285

**Contingency**

During 2019, the Company was served with a Statement of Claim from two joint interest owners that hold minority interests in a Unit, which is majority owned and operated by the Company. The plaintiffs are seeking judgment in the amount of \$56.0 million for unlawful conversion of their minority Unit interests (such amount based upon the alleged value of their minority Unit interests) or alternatively, judgment in the

amount of \$1.65 million, representing the amounts allegedly owed by the Company plus punitive damages, interest and other costs. The minority Unit owners have also alleged the Company has breached its fiduciary duties owing to the minority Unit owners and that without the approval of the minority Unit owners, the Company has conducted operations within the Unit area and outside of the Unit area without the approval of the minority Unit owners.

The Company has filed a Statement of Defence denying all material allegations of the minority Unit owners. The Company believes the claims are without merit and the amounts are unsubstantiated. Therefore, no provision for any amount has been recorded in the consolidated financial statements.

### **Unit Cost Calculation**

For the purpose of calculating unit costs, natural gas volumes have been converted to a boe using six thousand cubic feet equal to one barrel, unless otherwise stated. A boe conversion ratio of 6:1 is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. This conversion complies with 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
CGU	cash-generating unit
GJ	gigajoule
IFRS	International Financial Reporting Standards
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

### **Non-IFRS Measures**

This document contains the terms "adjusted funds flow", "free adjusted funds flow", "operating netback", "operating field netback", "net debt", "netbacks", "capital cost payout", "net debt to annualized adjusted funds flow 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 funds flow** - Tamarack's method of calculating adjusted funds flow may differ from other companies, and therefore may not be comparable to measures used by other companies. Adjusted funds flow 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; unrealized gain or loss on foreign exchange; unrealized gain or loss on cross-currency swaps; and gain or loss on dispositions. Tamarack uses adjusted funds flow as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. Adjusted funds flow per share is calculated using the same weighted average basic and diluted shares that are used in calculating income (loss) per share. The calculation of the Company's adjusted funds flows is summarized starting on page 14 in the section titled "Adjusted funds flow 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, foreign exchange and interest rate 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 9 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 surplus or deficit, including the fair value of cross-currency swaps and excluding the fair value of financial instruments and lease liabilities) 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 and lease liabilities):

(\$ thousands)	December 31, 2019	December 31, 2018 <sup>(1)</sup>
Accounts payable and accrued liabilities	\$37,809	\$41,966
Cross-currency swap liability	2,908	-
Accounts receivable	(42,219)	(21,211)
Prepaid expenses and deposits	(1,924)	(2,370)
Working capital deficiency (surplus)	(3,426)	18,385
Bank debt	192,907	161,495
<b>Net debt</b>	<b>\$189,481</b>	<b>\$179,880</b>

<sup>(1)</sup> IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

- (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 funds flow** – Management uses certain industry benchmarks, such as net debt to annualized adjusted funds flow, 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 funds flow for the most recently completed quarter. Management considers net debt to annualized adjusted funds flow as a key measure as it provides a snapshot of the overall financial health of the Company and its ability to pay off its debt and take on new debt, if necessary, using the most recent quarter's results.
- (f) **Free Adjusted Funds Flow** – Management uses certain industry benchmarks, such as free adjusted funds flow, 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 by taking adjusted funds flow and subtracting capital expenditures, excluding acquisitions and dispositions, Management believes that free adjusted funds flow provides a useful measure to determine Tamarack's ability to improve returns and to manage the long-term value of the business.
- (g) **Debt-Adjusted Production per Share Growth** - Management uses certain measurements such 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 were 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 a higher magnitude of their growth is financed through debt rather 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 so that investors can appreciate the impact that debt on a company's balance sheet has on its per share growth disclosure. In addition, it demonstrates the strength of one company's balance sheet relative to an over-leveraged peer, particularly in volatile commodity price environments where indebtedness could increase as a result of lower cash flows and higher debt service costs.

## Selected Quarterly Information

Three months ended	Dec. 31, 2019	Sep. 30, 2019	Jun. 30, 2019	Mar. 31, 2019	Dec. 31, 2018 <sup>(2)</sup>	Sep. 30, 2018 <sup>(2)</sup>	Jun. 30, 2018 <sup>(2)</sup>	Mar. 31, 2018 <sup>(2)</sup>
<b>Sales volumes</b>								
Natural gas (mcf/d)	54,462	55,224	53,451	50,576	50,262	49,943	52,376	51,879
Oil and NGL (bbls/d)	15,782	14,967	15,181	14,720	16,403	16,441	15,124	14,885
Average boe/d (6:1)	24,859	24,171	24,090	23,149	24,780	24,765	23,853	23,532
<b>Product prices</b>								
Natural gas (\$/mcf)	2.26	1.54	1.71	2.82	3.70	1.63	1.65	2.25
Oil and NGL (\$/bbl)	59.51	59.38	65.46	62.07	37.08	73.81	72.66	65.86
Oil equivalent (\$/boe)	42.72	40.28	45.04	45.62	32.05	52.29	49.69	46.62
<i>(000s, except per share amounts)</i>								
<b>Financial results</b>								
Gross revenues	97,699	89,579	98,741	95,047	73,075	119,134	107,859	98,736
Cash provided by operating activities	54,623	42,199	60,320	48,089	49,137	62,644	64,606	60,285
Adjusted funds flow <sup>(1)</sup>	54,742	49,283	57,906	57,503	38,346	68,579	61,005	58,545
Per share – basic	0.25	0.22	0.26	0.25	0.17	0.30	0.27	0.26
Per share – diluted	0.25	0.22	0.25	0.25	0.17	0.29	0.26	0.25
Net income (loss)	(50,546)	(111)	16,472	(4,826)	18,952	13,004	3,060	3,294
Per share – basic	(0.23)	(0.00)	0.07	(0.02)	0.08	0.06	0.01	0.01
Per share – diluted	(0.23)	(0.00)	0.07	(0.02)	0.08	0.06	0.01	0.01
Capital expenditures	22,954	58,867	25,902	71,243	25,798	78,149	52,674	69,630
Net acquisitions (dispositions)	250	3,847	4,771	1,074	(4,823)	–	(5,009)	2,790
Total assets	1,247,119	1,369,918	1,336,323	1,349,508	1,264,053	1,291,058	1,237,571	1,240,335
Net debt <sup>(1)</sup>	189,481	213,140	195,892	219,348	179,880	192,184	181,341	186,732
Bank debt	192,907	198,971	186,912	189,427	161,495	168,970	156,965	165,750
Decommissioning obligations	184,846	222,684	218,950	210,198	193,003	192,409	185,038	182,216

(1) Refer to definition of adjusted funds flow and net debt under “Non-IFRS Measures”.

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

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

- The volatility in commodity prices and oil price differentials and the resulting effect on revenue, cash provided by operating activities, adjusted funds flows and earnings.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices, foreign exchange and interest rates which can cause significant fluctuations in earnings due to unrealized gains and losses recognized on a quarterly basis.
- The Company recorded an impairment charge in Q4 2019 in the amount of \$68.0 million on its Cardium oil cash-generating unit (“CGU”) due to falling gas and NGL prices as that CGU has associated natural gas produced with the oil and includes Mannville gas wells and a Pekisko gas unit. The Company recorded an impairment charge in Q4 2018 in the amount of \$58.0 million on its Cardium oil CGU due to falling gas prices. In the same period, the Company also recorded an impairment reversal of \$53.0 million on its Viking oil CGU resulting in a net impairment expense of \$5.0 million in Q4 2018.

## Selected Annual Information

	2019	2018 <sup>(2)</sup>	2017 <sup>(2)</sup>
<b>Sales volumes</b>			
Natural gas (mcf/d)	53,444	51,108	48,893
Oil and NGL (bbls/d)	15,165	15,719	11,987
Average boe/d (6:1)	24,072	24,237	20,136
<b>Product prices</b>			
Natural gas (\$/mcf)	2.06	2.30	2.32
Oil and NGL (\$/bbl)	61.58	62.02	55.36
Oil equivalent (\$/boe)	43.37	45.08	38.60
<i>(000s, except per share amounts)</i>			
<b>Financial Results</b>			
Gross revenues	381,066	398,804	283,672
Net income (loss)	(39,011)	38,310	(13,924)
Per share – basic	(0.17)	0.17	(0.06)
Per share – diluted	(0.17)	0.16	(0.06)
Capital expenditures	178,966	226,251	192,302
Net acquisitions (dispositions)	9,942	(7,042)	81,971
Total assets	1,247,119	1,264,053	1,207,809
Net debt <sup>(1)</sup>	189,481	179,880	173,180
Bank debt	192,907	161,495	163,889

<sup>(1)</sup> Refer to definition of net debt under “Non-IFRS Measures”.

<sup>(2)</sup> IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Changes in Accounting Policies section in this MD&A.

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 and earnings.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices and foreign exchange and interest 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.
- 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 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 and NGL prices in the amount of \$68.0 million in Q4 2019. In Q4 2018, the Company recorded an impairment charge on its Cardium oil CGU, 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 for a net impairment of \$5.0 million. 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.

## **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 (“E&E”) assets**– The costs of drilling exploratory wells are initially capitalized as E&E assets pending the evaluation of commercial reserves. Commercial reserves are defined as the existence of proved and/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 operating 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 the use of shared infrastructure, geographic proximity, existence of active markets for the Company’s products, the way in which management monitors operations and materiality.

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) **IFRS 16** - Judgments are made by management in the application of IFRS 16 related to the incremental borrowing rate and lease term. The incremental borrowing rates are based on judgments including economic environment, term, currency, and the underlying risk inherent to the asset. The carrying balance of the right-of-use assets, lease obligations, and the resulting interest and depletion and depreciation expense, may differ due to changes in the market conditions and lease term. Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.
- (f) **Income taxes** – The determination of income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

### **Future Accounting Pronouncements**

In October 2018, the IASB issued amendments to the definition of a business in IFRS 3 “Business Combinations”. The amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. IFRS 3 continues to adopt a market participant’s perspective to determine whether an acquired set of activities and assets is a business. The amendments clarify the minimum requirements for a business; remove the assessment of whether market participants are capable of replacing any missing elements; add guidance to help entities assess whether an acquired process is substantive; narrow the definitions of a business and of outputs; and introduce an optional fair value concentration test. The concentration test is a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or a group of similar identifiable assets. If an entity chooses not to apply the concentration test, or the test is failed, then the assessment focuses on the existence of a substantive process.

The amendments to IFRS 3 are effective for annual reporting periods beginning on or after January 1, 2020 and apply prospectively.

## **Changes in Accounting Policies**

### **IFRS 16, Leases:**

Effective January 1, 2019, the Company adopted IFRS 16. The Company has applied the new standard using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening deficit and applies the standard prospectively. Therefore, the comparative information in the financial statements has not been restated.

On adoption, management elected to use the following practical expedients permitted under the new standard:

- account for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases;
- account for lease payments as an expense and not recognize a ROU asset if the underlying asset is of a low dollar value; and
- the use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease.

IFRS 16 requires entities to recognize lease liabilities in relation to leases which had previously been classified as operating leases under the principles of IAS 17, “Leases”. Under the principles of IFRS 16, these leases have been measured at the present value of the remaining lease payments, discounted using the Company’s incremental borrowing rates at January 1, 2019. Incremental borrowing rates as at January 1, 2019 ranged from 4.5% to 8.8% with a weighted average of 5.6%. The associated ROU assets were measured at the amount equal to the lease liability on January 1, 2019.

Adopting IFRS 16 impacted Tamarack’s lease liabilities and ROU assets as follows, as at January 1, 2019:

- recorded lease liabilities of \$37.2 million, \$25.9 million of which is the current portion; and
- recorded ROU assets of \$37.2 million.

Adopting IFRS 16 impacted Tamarack’s Q4/19 and the year ended December 31, 2019 financial results compared with what would have occurred had it not adopted the new accounting policy as follows:

- decreased production costs in the amount of \$0.8 million and \$4.0 million respectively;
- increased DDA&A expenses in the amount of \$0.6 million and \$2.7 million respectively; and
- increased finance expenses in the amount of \$0.2 million and \$1.2 million respectively.

## **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, 2019 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, 2019.

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 Annual Information Form for the year ended December 31, 2019, which can be found on SEDAR at [www.sedar.com](http://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;
- the duration and future direction of the Curtailment Order;
- the impact of the Curtailment Order on Canadian crude prices in 2020;
- the availability, size, terms, use and renewal of the Facility;
- the performance of the Viking waterflood project, including oil recoveries and , corporate decline rates and production rates in 2020 and 2021; Tamarack's commitment to its environmental, social and governance responsibilities;
- 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 intention 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 expectation of generating adjusted funds flow that exceeds its budgeted capital expenditures (excluding tuck-in acquisitions);
- Tamarack's position to withstand further crude oil price volatility;

- future drilling plans;
- the capital cost payout of wells and Tamarack's strategy of focusing on drilling wells that target a certain return on capital cost payout and Tamarack's ability to control cost or reduce capital, production and transportation costs;
- deferred tax liabilities;
- future investment and capital allocation strategy;
- planned waterflood investment in 2020 and expected well conversions and drilling of additional injection wells;
- Tamarack's 2020 budget and 2020 guidance levels;
- Tamarack's execution to be fully self-funded in 2020;
- estimates for debt-adjusted production per share in 2020;
- expectations as to royalty rates as a percentage of revenue;
- contractual obligations and commitments;
- the estimates used to calculate the decommissioning obligations and depletion of PP&E;
- expectations for realized commodity prices in 2020;
- Tamarack's intent to use excess total adjusted funds flows to purchase and cancel shares under the NCIB or to close additional accretive tuck-in acquisitions;
- future RSU settlements;
- Tamarack's expectation of challenging market conditions for the long term;
- Tamarack's expectation of risk mitigation and realized price improvements from exposure to diversified gas markets;
- expectations for oil, NGL and natural gas pricing in 2020 and beyond; and
- expectations for oil, NGL and natural gas weighting in 2020.

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 ability to explore diversified gas markets;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the base curtailment limits and expected duration of the Curtailment Order;
- drilling results, including field production rates and decline rates;
- decrease in corporate declines in 2020 and 2021 as a result of the positive response from ongoing waterflood development;
- 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 Expense”, “Interest Expense”, “Depletion, Depreciation, Amortization and Accretion (“DDA&A”)”, “Impairment”, “Income Taxes”, “Adjusted Funds Flow and Net Income (Loss)”, “Capital Expenditures (Including Exploration and Evaluation Expenditures)”, “Property Acquisitions”, “Share Capital”, “Liquidity and Capital Resources”, “Bank Debt”, “Guidance”, “Commitments”, “Contingency”, “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 markets 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, 2019, which may be accessed on Tamarack's SEDAR profile at [www.sedar.com](http://www.sedar.com) or on the Company's website at [www.tamarackvalley.ca](http://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 funds flow, operating netback, net debt to annualized adjusted funds flow ratio, capital cost payout, net 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.



## MANAGEMENT'S REPORT

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

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

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

*(signed)*  
Brian Schmidt  
President & Chief Executive Officer

*(signed)*  
June-Marie Innes  
Interim Chief Financial Officer

Calgary, Alberta  
March 4, 2020



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## INDEPENDENT AUDITORS' REPORT

To the Shareholders of Tamarack Valley Energy Ltd.

### **Opinion**

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

- the consolidated balance sheets as at December 31, 2019 and December 31, 2018
- the consolidated statements of income (loss) and comprehensive income (loss) for the years then ended
- the consolidated statements of changes in shareholders' equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

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

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2019 and December 31, 2018, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

### **Basis for Opinion**

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

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

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

### **Other Information**

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



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

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

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

We have nothing to report in this regard.

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

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

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

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

***Auditors' Responsibilities for the Audit of the Financial Statements***

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

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

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

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



We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.  
The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this auditors' report is John Waiand.

*KPMG LLP*

Chartered Professional Accountants  
Calgary, Canada  
March 4, 2020

# TAMARACK VALLEY ENERGY LTD.

Consolidated Balance Sheets  
(thousands)

	December 31, 2019	December 31, 2018
<b>Assets</b>		
Current assets:		
Accounts receivable (note 5)	\$42,219	\$21,211
Prepaid expenses and deposits	1,924	2,370
Fair value of financial instruments (note 5)	114	20,518
	44,257	44,099
Fair value of financial instruments (note 5)	275	1,533
Property, plant and equipment (note 7)	1,200,950	1,215,633
Exploration and evaluation assets (note 9)	1,637	2,788
	\$1,247,119	\$1,264,053
<b>Liabilities and Shareholders' Equity</b>		
Current liabilities:		
Accounts payable and accrued liabilities	\$37,809	\$41,966
Lease liabilities (note 12)	2,209	—
Cross-currency swap liability (note 15)	2,908	—
Fair value of financial instruments (note 5)	4,475	2,391
	47,401	44,357
Bank debt (note 18)	192,907	161,495
Lease liabilities (note 12)	9,961	—
Decommissioning obligations (note 10)	184,846	193,003
Deferred tax liability (note 14)	38,229	52,627
Shareholders' equity:		
Share capital (note 16)	832,799	848,249
Treasury shares (note 16)	(969)	(3,377)
Contributed surplus	47,811	34,554
Deficit	(105,866)	(66,855)
	773,775	812,571
Subsequent event (note 5)		
Commitments (note 20)		
Contingency (note 21)		
	\$1,247,119	\$1,264,053

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:

(signed)

Floyd Price  
Director

(signed)

John Leach  
Director

# TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)

For the years ended December 31, 2019 and 2018

(thousands, except per share amounts)

	2019	2018
<b>Revenue:</b>		
Oil and natural gas (note 6)	\$381,066	\$398,804
Processing income (note 6)	1,750	658
Royalties	(39,060)	(39,901)
Realized loss on financial instruments (note 5)	(12,516)	(17,945)
Unrealized gain (loss) on financial instruments (note 5)	(23,746)	27,137
	<b>307,494</b>	<b>368,753</b>
<b>Expenses:</b>		
Production	89,897	93,683
General and administration	12,464	13,386
Stock-based compensation (note 19)	9,689	8,873
Finance (note 15)	13,569	12,178
Depletion, depreciation and amortization (note 7 and 9)	167,311	177,576
Gain on disposition of property, plant and equipment (note 7)	(27)	(1,085)
Impairment of property, plant and equipment (note 8)	68,000	5,000
	<b>360,903</b>	<b>309,611</b>
Income (loss) before taxes	(53,409)	59,142
Deferred income tax recovery (expense) (note 14)	14,398	(20,832)
Net income (loss) and comprehensive income (loss)	<b>\$(39,011)</b>	<b>\$38,310</b>
<b>Net income (loss) per share (note 17):</b>		
Basic	\$(0.17)	\$ 0.17
Diluted	\$(0.17)	\$ 0.16

See accompanying notes to the consolidated financial statements.

# TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Changes in Shareholders' Equity  
(thousands)

	Number of common shares, net of treasury shares	Share capital	Treasury shares	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2018	228,510	\$850,357	\$ –	\$27,180	\$(103,682)	\$773,855
Issue of common shares	1,780	5,439	–	–	–	5,439
Purchase of common shares for cancellation	(3,025)	(11,593)	–	1,371	(1,483)	(11,705)
Purchase of common shares for RSU exercise	(1,804)	–	(5,799)	–	–	(5,799)
RSU exercise	611	–	2,422	(2,422)	–	–
Transfer on exercise of stock options and RSUs	–	4,046	–	(4,046)	–	–
Stock-based compensation	–	–	–	12,471	–	12,471
Net income	–	–	–	–	38,310	38,310
Balance at December 31, 2018	226,072	\$848,249	\$(3,377)	\$34,554	\$(66,855)	\$812,571
Balance at January 1, 2019	226,072	\$848,249	\$(3,377)	\$34,554	\$(66,855)	\$812,571
Issue of common shares	15	41	–	–	–	41
Settlement of RSUs	163	595	–	(782)	–	(187)
Purchase of common shares for cancellation	(4,181)	(16,112)	–	7,852	–	(8,260)
Purchase of common shares for RSU exercise	(1,641)	–	(3,452)	–	–	(3,452)
RSU exercise	2,365	–	5,860	(5,860)	–	–
Transfer on exercise of stock options	–	26	–	(26)	–	–
Stock-based compensation	–	–	–	12,073	–	12,073
Net loss	–	–	–	–	(39,011)	(39,011)
Balance at December 31, 2019	222,793	\$832,799	\$(969)	\$47,811	\$(105,866)	\$773,775

See accompanying notes to the consolidated financial statements.

# TAMARACK VALLEY ENERGY LTD.

Consolidated Statements of Cash Flows  
For the years ended December 31, 2019 and 2018  
(thousands)

	2019	2018
Cash provided by (used in):		
Operating:		
Net income (loss)	\$(39,011)	\$38,310
Depletion, depreciation and amortization (note 7 and 9)	167,311	177,576
Stock-based compensation (note 19)	9,689	8,873
Gain on disposition of property, plant and equipment (note 7)	(27)	(1,085)
Accretion expense on decommissioning obligations (note 10)	4,075	4,106
Unrealized (gain) loss on financial instruments (note 5)	23,746	(27,137)
Unrealized gain on foreign exchange (note 15)	(2,859)	–
Unrealized loss on cross-currency swaps (note 15)	2,908	–
Impairment of property, plant and equipment (note 8)	68,000	5,000
Deferred income tax (recovery) expense (note 14)	(14,398)	20,832
Abandonment expenditures (note 10)	(3,154)	(1,901)
Changes in non-cash working capital (note 13)	(11,049)	12,098
Cash provided by operating activities	205,231	236,672
Financing:		
Change in bank debt (note 18)	34,271	(2,394)
Proceeds from issuance of shares (note 16)	41	5,439
Purchase of common shares for cancellation (note 16)	(8,260)	(11,705)
Purchase of common shares for RSU exercises (note 16)	(3,639)	(5,799)
Purchase of leased asset (note 12)	(22,328)	–
Repayment of lease liabilities (note 12)	(2,738)	–
Cash used in financing activities	(2,653)	(14,459)
Investing:		
Property, plant and equipment additions (note 7)	(179,088)	(223,319)
Exploration and evaluation additions (note 9)	122	(2,932)
Acquisitions (note 7)	(9,942)	(2,847)
Proceeds from disposal of property, plant and equipment	–	9,889
Changes in non-cash working capital (note 13)	(13,670)	(3,004)
Cash used in investing activities	(202,578)	(222,213)
Change in cash and cash equivalents	–	–
Cash and cash equivalents, beginning of year	–	–
Cash and cash equivalents, end of year	\$ –	\$ –

See accompanying notes to the consolidated financial statements.

# TAMARACK VALLEY ENERGY LTD.

Notes to the Consolidated Financial Statements  
For the years ended December 31, 2019 and 2018  
(thousands, except per share and per unit amounts)

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## 1. Reporting entity:

Tamarack Valley Energy Ltd. (“Tamarack” or the “Company”) is a corporation existing under the laws of Alberta. The Company is engaged in the exploration for, development and production of, oil and natural gas. The consolidated financial statements of Tamarack consist of the Company and its subsidiaries. The Company has the following wholly owned subsidiaries, which are incorporated in Canada: Tamarack Acquisition Corp. and Tamarack Valley Ridge Holdings Ltd. The Company also has a subsidiary incorporated in the United States: Tamarack Ridge Resources Inc. No assets are held within Tamarack Ridge Resources Inc. or Tamarack Valley Ridge Holdings Ltd. Tamarack is a publicly traded company, incorporated and domiciled in Canada. The address of its registered office is Suite 4300, 888 – 3<sup>rd</sup> Street S.W., Calgary, Alberta, T2P 5C5. The address of its head office is currently Suite 600, 425 – 1<sup>st</sup> Street S.W., Calgary, Alberta, T2P 3L8.

## 2. Basis of preparation:

### (a) Statement of compliance:

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”).

The consolidated financial statements were authorized for issue by the Board of Directors on March 4, 2020.

### (b) Basis of measurement:

The consolidated financial statements have been prepared on the historical cost basis except for certain derivative financial instruments which are measured at fair value.

### (c) Functional and presentation currency:

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

### (d) Use of estimates and judgments:

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

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

## TAMARACK VALLEY ENERGY LTD.

Notes to the Consolidated Financial Statements  
For the years ended December 31, 2019 and 2018  
(thousands, except per share and per unit amounts)

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### *i) Critical judgments in applying accounting policies*

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

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

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

The application of the Company's accounting policy for E&E assets requires management to make certain judgments as to future events and circumstances as to whether economic quantities of reserves have been found in assessing if technical feasibility and commercial viability has been achieved.

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

Judgments are made by management in the application of IFRS 16 related to the incremental borrowing rate and lease term. The incremental borrowing rates are based on judgments including economic environment, term, currency, and the underlying risk inherent to the asset. The carrying balance of the right-of-use assets, lease obligations, and the resulting interest and depletion and depreciation expense, may differ due to changes in the market conditions and lease term. Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

### *ii) Key sources of estimation uncertainty*

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

Estimation of recoverable quantities of proven and probable reserves include estimates and assumptions regarding future commodity prices, exchange rates, discount rates and production and transportation costs for future cash flows and the amount and timing of further development capital as well as the interpretation of complex geological and geophysical models and data. Changes in reported reserves can affect the impairment of assets, the decommissioning obligations, the economic feasibility of E&E assets and the amounts reported for depletion, depreciation and

# TAMARACK VALLEY ENERGY LTD.

Notes to the Consolidated Financial Statements  
For the years ended December 31, 2019 and 2018  
(thousands, except per share and per unit amounts)

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amortization of property, plant and equipment. These reserve estimates are verified by third party professional engineers, who work with information provided by the Company to establish reserve determinations in accordance with National Instrument 51-101.

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

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

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

### 3. Significant accounting policies:

The accounting policies set out below have been applied consistently by the Company and its subsidiaries to all years presented in these consolidated financial statements, except as provided for in (m) below.

(a) Basis of consolidation:

*i) Subsidiaries:*

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

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

*ii) Jointly owned assets:*

Many of the Company's oil and natural gas activities involve jointly owned assets. The consolidated financial statements include the Company's share of these jointly owned assets and a proportionate share of the relevant revenue and related costs. The

## TAMARACK VALLEY ENERGY LTD.

Notes to the Consolidated Financial Statements  
For the years ended December 31, 2019 and 2018  
(thousands, except per share and per unit amounts)

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relationship with jointly owned asset partners has been referred to as joint venture in the remainder of the financial statements as is common in the Canadian oil and gas industry.

*iii) Transactions eliminated on consolidation:*

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

(b) Financial instruments:

*i) Financial instruments:*

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

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

- Amortized cost - A financial asset is measured at amortized cost if the objective of the business model is to hold the financial asset for the collection of the cash flows; and all contractual cash flows represent only principal and interest on that principal. All financial liabilities are measured at amortized cost using the effective interest method except for liabilities incurred for the purposes of selling or repurchasing in the short-term, if they are held-for trading and those that meet the definition of a derivative.

- Fair value through other comprehensive income ("FVOCI") - A financial asset shall be measured at FVOCI if the financial asset is held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets; and the contractual terms of the financial asset give rise on specified dates to cash flows that are Solely Payment of Principal and Interest ("SPPI") on the principal amount outstanding.

- Fair value through profit or loss ("FVTPL") - All financial assets that do not meet the definition of being measured at amortized cost or FVOCI are measured at FVTPL, this includes all derivative financial assets. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. For financial assets and liabilities, the Company may make an irrevocable election to designate an asset at FVTPL. If the election is made it is irrevocable, meaning that asset, liability, or group of financial instruments must be recorded at FVTPL until that asset, liability or group of financial instruments are derecognized.

Financial assets and liabilities are offset and the net amount is reported on the balance sheet when there is a legally enforceable right to offset the recognized amounts, and

## TAMARACK VALLEY ENERGY LTD.

Notes to the Consolidated Financial Statements  
For the years ended December 31, 2019 and 2018  
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there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

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

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

### *ii) Share capital:*

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

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

#### *i) Recognition and measurement:*

E&E expenditures:

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

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

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

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

Upon determination of proven and/or probable reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to property, plant and equipment.

Development and production costs:

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

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

*ii) Subsequent costs:*

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

*iii) Depletion, depreciation and amortization:*

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

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

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

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

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

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

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### (d) Leased assets:

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

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

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

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

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

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

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

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

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

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

(e) Impairment:

i) *Financial assets:*

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

ii) *Non-financial assets:*

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

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

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

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

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

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

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

(f) Share based payments:

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

(g) Provisions:

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

*i) Decommissioning obligations:*

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

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

*ii) Onerous contracts:*

A provision for onerous contracts is recognized when the expected benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting its obligations under the contract. The provision is measured at the present value of the lower of the expected cost of terminating the contract and the expected

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net cost of continuing with the contract. Before a provision is established, the Company recognizes any impairment loss on associated assets.

(h) Revenue:

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

(i) Finance income and expenses:

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

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

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

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

(j) Income tax:

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

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

Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill.

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Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

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

(k) Flow-through shares:

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

(l) Earnings per share:

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

(m) Changes in accounting policies:

Effective January 1, 2019, the Company adopted IFRS 16, "Leases" ("IFRS 16"). The Company has applied IFRS 16 using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening deficit and applies the standard prospectively. Therefore, the comparative information in the Company's consolidated balance sheet and, consolidated statements of income (loss) and comprehensive income (loss), changes in shareholders' equity and cash flows have not been restated. On adoption, management elected to use the following practical expedients permitted under IFRS 16:

- account for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases;
- account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of a low dollar value (less than US \$5 thousand); and
- the use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease.

The effect of initially applying the standard was a \$37.2 million increase to lease liabilities, with a corresponding right-of-use-asset recorded. The right-of-use asset was measured at the amount equal to the lease liability on January 1, 2019 with no impact on opening deficit.

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The following table shows the impact of the implementation of IFRS 16 on the operating lease commitments previously disclosed in note 20, Commitments.

(\$ thousands)	As at January 1, 2019
Processing facilities rental fee	28,374
Increase in rental fee from purchase option election	10,160
Surface leases	5,272
Lease component of lease commitments	43,806
Impact of discounting	(6,570)
Lease liabilities recognized	37,236

Prior to the adoption of IFRS 16, these leases were treated as operating leases which were recognized in production expense on a straight-line basis over the term of the lease.

(n) Future standards and interpretations:

In October 2018, the IASB issued amendments to the definition of a business in IFRS 3 “Business Combinations”. The amendments are intended to assist entities to determine whether a transaction should be accounted for as a business combination or as an asset acquisition. IFRS 3 continues to adopt a market participant’s perspective to determine whether an acquired set of activities and assets is a business. The amendments clarify the minimum requirements for a business; remove the assessment of whether market participants are capable of replacing any missing elements; add guidance to help entities assess whether an acquired process is substantive; narrow the definitions of a business and of outputs; and introduce an optional fair value concentration test. The concentration test is a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or a group of similar identifiable assets. If an entity chooses not to apply the concentration test, or the test is failed, then the assessment focuses on the existence of a substantive process.

The amendments to IFRS 3 are effective for annual reporting periods beginning on or after January 1, 2020 and apply prospectively.

#### 4. Determination of fair values:

A number of the Company’s accounting policies and disclosures require the determination of fair value, for both financial and non-financial assets and liabilities. Fair values have been determined for measurement and/or disclosure purposes based on the following methods outlined below. The Company’s fair value measurements are classified as one of the following levels of the fair value hierarchy:

Level 1 – inputs represent unadjusted quoted prices in active markets for identical assets and liabilities. An active market is characterized by a high volume of transactions that provides pricing information on an ongoing basis.

Level 2 – inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These valuations are based on inputs that can be observed or corroborated in the marketplace, such as market interest rates or forward prices for commodities.

Level 3 – inputs for the asset or liability are not based on observable market data.

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The Company aims to maximize the use of observable inputs when preparing calculations of fair value. Classification of each measurement into the fair value hierarchy is based on the lowest level of input that is significant to the fair value calculation. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

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

The fair value of property, plant and equipment recognized in an acquisition is based on market values. The market value of property, plant and equipment is the estimated amount for which property, plant and equipment could be exchanged on the acquisition date between a willing buyer and a willing seller in an arm's length transaction after proper marketing wherein the parties had each acted knowledgeably, prudently and without compulsion. The market value of oil and natural gas interests (included in property, plant and equipment) is estimated with reference to the discounted cash flows expected to be derived from oil and natural gas production based on externally prepared reserve reports. The risk-adjusted discount rate is specific to the asset with reference to general market conditions. The market value of other items of property, plant and equipment and E&E assets is based on the quoted market prices for similar items.

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

The fair value of accounts receivable and accounts payable and accrued liabilities is estimated as the present value of future cash flows, discounted at the market rate of interest at the reporting date. At December 31, 2019 and 2018, the fair value of these balances approximated their carrying value due to their short term to maturity.

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

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

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

(d) Derivatives:

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted amounts and a risk-free interest rate (based on published government rates). The fair value of options and costless collars is based on option models that use level 2 inputs, being published information with respect to volatility, prices and interest rates. Derivatives and cross-currency swaps are recorded on the balance sheet at fair value with the change in fair value being recognized as an unrealized gain or loss in profit or loss.

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### 5. Financial risk management:

(a) Overview:

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

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

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

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

(b) Credit risk:

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

(\$ thousands)	Carrying amount	
	2019	2018
As at December 31,		
Accounts receivable	<b>\$42,219</b>	\$21,211
Fair value of financial instruments	<b>389</b>	22,051
Total	<b>\$42,608</b>	\$43,262

Accounts receivable:

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

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

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

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

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

The Company does not anticipate any default as it transacts with creditworthy customers and management does not expect any losses from non-performance by these customers. The lifetime expected credit losses allowances related to the Company's oil and natural gas marketers and joint venture receivables were nominal as at and for the years ended December 31, 2019 and 2018.

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

(\$ thousands)	Carrying amount	
	2019	2018
As at December 31,		
Oil and natural gas marketing companies	\$33,708	\$14,173
Joint venture partners	3,542	4,555
Other	4,969	2,483
Total accounts receivable	\$42,219	\$21,211

The Company's six most significant customers, four Canadian oil and natural gas marketers, and two joint venture partners, account for \$29.5 million of the accounts receivables at December 31, 2019 (December 31, 2018: eight Canadian oil and natural gas marketers, and one joint venture partner accounted for \$12.7 million). The Company has the ability to offset approximately 90% of the remaining amounts against current accounts payable from the same joint venture partners.

As at December 31, 2019 and 2018, the Company's accounts receivable is aged as follows:

(\$ thousands)	2019	2018
Current (less than 90 days)	\$40,503	\$20,189
Past due (more than 90 days)	1,716	1,022
Total accounts receivable	\$42,219	\$21,211

(c) Liquidity risk:

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

Typically, the Company ensures that it has sufficient cash or banking line available to meet expected operational expenses for a period of 30 days, including the servicing of financial obligations; this excludes the potential impact of extreme circumstances that cannot reasonably be predicted, such as natural disasters. To achieve this objective, the Company prepares annual

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capital expenditure budgets, which are regularly monitored and updated as considered necessary. Further, the Company utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. The Company also attempts to match its payment cycle with collection of oil and natural gas revenue on the 25th of each month. In addition, the Company maintains a \$350,000 credit facility to provide capital when needed, of which \$156,919 was available at the end of 2019.

The timing of cash flows relating to financial liabilities as at December 31, 2019 is as follows:

(\$ thousands)	Total	1 Year	2 to 3 years	Beyond 3 years
Account payable and accrued liabilities	\$37,809	\$37,809	\$-	\$-
Fair value of financial instruments	4,475	4,475	-	-
Cross currency swap liability	2,908	2,908	-	-
Bank debt	192,907	-	192,907	-
Total financial liabilities	\$238,099	\$45,192	\$192,907	\$-

Refer to note 12 for a maturity analysis of the Company's lease liabilities.

(d) Market risk:

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

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

Currency risk:

Prices for oil are determined in global markets and generally denominated in United States dollars. Natural gas prices obtained by the Company are influenced by both US and Canadian demand and the corresponding North American supply. The exchange rate effect cannot be quantified but generally a decrease in the value of the \$CDN as compared to the \$US will increase the prices received by the Company for its petroleum and natural gas sales. The Company holds hedges to mitigate foreign exchange risk as detailed in the table below in addition to cross-currency swaps to remove the foreign exchange risk of LIBOR based borrowings (see note 15).

Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The interest charged on the outstanding bank debt fluctuates with the interest rates posted by the lenders. The Company is exposed to interest rate risk and has entered into mitigating interest rate swaps to cover a portion of this exposure. Had the borrowing rate been 100 basis points higher (or lower) throughout the year ended December 31, 2019, net loss would have been affected by \$1,379 (December 31, 2018 – \$1,160) based on the average debt balance outstanding during the year.

Commodity price risk:

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted by not only

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the relationship between the Canadian and United States dollar but also world economic events that dictate the levels of supply and demand.

At December 31, 2019, the Company held derivative commodity, foreign exchange and interest rate contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn \$000s)
Crude oil	4,000 bbls/day	January 1, 2020 – March 31, 2020	WTI fixed price	US \$60.78	\$72
Crude oil	2,700 bbls/day	April 1, 2020 – June 30, 2020	WTI fixed price	US \$58.27	(\$310)
Crude oil	7,000 bbls/day	January 1, 2020 – December 31, 2020	Edm par diff	US (\$7.54)	(\$4,237)
Foreign exchange	1,000,000 US\$/mth	January 1, 2020 – March 31, 2020	Exchange rate	Cdn \$1.3405	\$127
Interest rate	25,000,000 US\$/mth	January 1, 2020 – April 24, 2023	Fixed rate	1.90%	\$72
Interest rate	25,000,000 US\$/mth	January 1, 2020 – June 14, 2023	Fixed rate	1.75%	\$190
					(\$4,086)

At December 31, 2019, Tamarack's commodity, foreign exchange and interest rate contracts were fair valued with a liability of \$4,086 (December 31, 2018 - \$19,660 asset) recorded on the balance sheet. The Company had an unrealized loss of \$23,746 recorded in earnings for the year ended December 31, 2019 (December 31, 2018 - \$27,137 unrealized gain).

Subject Contract	Effect of an increase in oil price, exchange rate or interest rate on after-tax earnings	Effect of a decrease in oil price, exchange rate or interest rate on after-tax earnings
Cdn \$1.00 change in the oil price	(\$895)	\$895
Cdn \$0.01 change in the exchange rate	(\$22)	\$23
0.25% change in the interest rate	(\$298)	\$298

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, 2019, the Company held the following physical commodity contracts.

Subject contract	Quantity	Remaining term	Hedge type	Strike price
Natural gas	7,901 GJ/day	January 1, 2020 – January 31, 2020	AECO fixed price	Cdn \$2.64
Natural gas	2,320 GJ/day	February 1, 2020 – February 29, 2020	AECO fixed price	Cdn \$2.30
Natural gas	15,000 mmbtu/day	February 1, 2020 – February 29, 2020	AECO/Henry Hub differential	Index – US \$0.56
Natural gas	5,000 GJ/day	March 1, 2020 – March 31, 2020	AECO fixed price	Cdn \$2.45
Natural gas	15,000 mmbtu/day	March 1, 2020 – March 31, 2020	AECO/Henry Hub differential	Index – US \$1.16
Natural gas	15,000 mmbtu/day	April 1, 2020 – October 31, 2020	AECO/Henry Hub differential	Index – US \$1.23

Risk management contracts assets and liabilities are offset, and the net amount presented in the balance sheet, when the Company has a legal right to offset the amounts and intends to settle them on a net basis or to realize the asset and settle the liability simultaneously.

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

Gross Amounts (\$ thousands)	December 31, 2019	December 31, 2018
Risk management contracts		
Current asset	\$114	\$20,518
Long-term asset	275	1,533
Current liability	(4,475)	(2,391)
Long-term liability	–	–
Balance, end of the year	<b>\$(4,086)</b>	\$19,660

Since December 31, 2019, the Company adjusted its derivative portfolio by entering into a transaction that cancelled a portion of existing derivative contracts and re-entered into new derivative contracts. As at March 4, 2020, the Company held derivative commodity, foreign exchange and interest rate contracts as follows:

Subject contract	Quantity	Term	Hedge type	Strike price
Crude oil	1,000 bbls/day	March 4, 2020 – March 31, 2020	WTI fixed price	US \$59.86
Crude oil	500 bbls/day	April 1, 2020 – June 30, 2020	WTI fixed price	US \$59.17
Crude oil	3,000 bbls/day	July 1, 2020 – September 30, 2020	WTI fixed price	US \$54.57
Crude oil	3,000 bbls/day	October 1, 2020 – December 31, 2020	WTI fixed price *	US \$54.57
Crude oil	5,650 bbls/day	March 4, 2020 – March 31, 2020	WTI Put	US \$58.00
Crude oil	4,400 bbls/day	April 1, 2020 – June 30, 2020	WTI Put	US \$58.00
Crude oil	1,700 bbls/day	July 1, 2020 – September 30, 2020	WTI Put	US \$58.00
Crude oil	7,000 bbls/day	March 4, 2020 – December 31, 2020	WTI/Edm par differential	US (\$7.54)
Foreign exchange	1,000,000 US\$/mth	March 4, 2020 – March 31, 2020	Exchange rate	Cdn \$1.3405
Foreign exchange	3,000,000 US\$/mth	April 1, 2020 – June 30, 2020	Exchange rate	Cdn \$1.3271
Interest rate	25,000,000 US\$/mth	March 4, 2020 – April 24, 2023	Fixed rate	1.90%
Interest rate	25,000,000 US\$/mth	March 4, 2020 – June 14, 2023	Fixed rate	1.75%

\* Extendable for an additional six months at the counter-parties discretion.

Since December 31, 2019, the Company has not entered into any additional physical contracts.

### (e) Capital management:

The Company's policy is to maintain a strong capital base to maintain investor, creditor and market confidence and to sustain future development of the business. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Company considers its capital structure to include shareholders' equity, bank debt and working capital. In order to maintain or adjust the capital structure, the Company may issue shares, use debt and adjust its capital spending to manage current and projected debt levels.

The Company monitors capital based on the ratio of net debt to annualized adjusted funds flow. This ratio is calculated as net debt, defined as outstanding bank debt plus accounts payable and accrued liabilities and cross-currency swap liabilities minus accounts receivable and prepaid expenses and deposits and cross-currency swap assets divided by adjusted funds flow for the most

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recent calendar quarter and then annualized. Tamarack calculates adjusted funds flow as cash provided by operating activities before the changes in non-cash working capital related to operating activities, abandonment expenditures and transaction costs. The Company's strategy during a period of stable commodity prices is to maintain a ratio of not more than 1.5 times. This ratio may increase or decrease at certain times as a result of acquisitions, timing of employing capital versus bringing wells on production or significant upward/downward fluctuations in commodity prices.

With the recent decrease in commodity prices and increased volatility in the oil and gas industry, Tamarack's strategy remains focused on preserving its balance sheet by limiting capital spending to projected cash provided by operating activities, using strip prices.

The Company prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors.

As at December 31, 2019, the Company's ratio of net debt to annualized fourth quarter adjusted funds flow was 0.9 to 1 (December 31, 2018 – 1.2 to 1).

(\$ thousands)	December 31, 2019	December 31, 2018
Working capital deficiency (surplus)	<b>\$(3,426)</b>	\$18,385
Bank debt	<b>192,907</b>	161,495
Net debt	<b>189,481</b>	179,880
Quarterly adjusted funds flow	<b>\$54,742</b>	\$38,346
Annualized factor	<b>4</b>	4
Annualized adjusted funds flow	<b>218,968</b>	153,384
Net debt to annualized adjusted funds flow	<b>0.9x</b>	1.2x

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

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

### 6. Revenue:

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

Revenue is recognized when the Company gives up control of the unit of production at the delivery point agreed to under the terms of the contract. The amount of revenue recognized is based on the agreed transaction price and the volumes delivered. Any variability in the transaction price relates specifically to Tamarack's efforts to transfer production and therefore the resulting revenue is allocated to the production volumes delivered in the period to which the variability relates. The Company does not have any factors considered to be constraining in the recognition of revenue with variable pricing factors. The Company's contracts with customers generally have a term of one year or less, except in

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the case of certain natural gas contracts, whereby delivery takes place throughout the contract period. Revenues are normally collected on the business day nearest the 25th day of the month following sale.

The Company's revenues were primarily generated in its core areas: the Cardium oil play in the Wilson Creek/Alder Flats areas of central Alberta; the Viking oil play in central and southern Alberta and west central Saskatchewan; and the Barons Sand oil play in the Penny area of southern Alberta. The Company's customers are oil and natural gas marketers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing volumes to numerous oil and natural gas marketers under customary industry sale and payment terms. As at December 31, 2019, revenue was earned from customers, of which four customers account for \$28.7 million of the accounts receivable at December 31, 2019 (December 31, 2018, four customers accounted for \$11.9 million).

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

(\$ thousands)	Years ended December 31,	
	2019	2018
Light oil	<b>\$316,819</b>	\$322,537
Heavy oil	<b>8,876</b>	11,915
Natural gas	<b>40,231</b>	42,978
Natural gas liquids	<b>15,140</b>	21,374
Oil and natural gas revenue	<b>\$381,066</b>	\$398,804
Processing income	<b>1,750</b>	658
Total revenue	<b>\$382,816</b>	\$399,462

Refer to note 5 for a listing of physical delivery contracts as at December 31, 2019.

Included in accounts receivable at December 31, 2019 was \$34.7 million (December 31, 2018 - \$13.8 million) of accrued production revenue related to deliveries for the month then ended. There were no significant adjustments for prior period accrued production revenue reflected in the current period. As at December 31, 2019, the Company did not have any contracts for the sale of its future production beyond one year in term, except certain natural gas contracts that expire in 2022.

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### 7. Property, plant and equipment:

(\$ thousands)	Oil and natural gas interests	Other assets	Total
Cost:			
Balance at January 1, 2018	\$1,624,550	\$1,368	\$1,625,918
Property acquisitions	2,847	–	2,847
Cash additions	223,102	217	223,319
Decommissioning costs	13,379	–	13,379
Stock-based compensation	3,598	–	3,598
Transfer from exploration and evaluation assets (note 9)	894	–	894
Disposals	(10,215)	–	(10,215)
Balance at December 31, 2018	1,858,155	1,585	1,859,740
Right-of-use assets (note 12)	37,236	–	37,236
Property acquisitions	10,598	–	10,598
Cash additions	178,678	410	179,088
Decommissioning costs	(8,719)	–	(8,719)
Stock-based compensation	2,384	–	2,384
Transfer from exploration and evaluation assets (note 9)	30	–	30
Disposals	(2,035)	–	(2,035)
Balance at December 31, 2019	\$2,076,327	\$1,995	\$2,078,322
Accumulated depletion, depreciation and impairment losses:			
Balance at January 1, 2018	\$462,969	\$677	\$463,646
Depletion and depreciation	176,255	243	176,498
Disposals	(1,037)	–	(1,037)
Impairment, net (note 8)	5,000	–	5,000
Balance at December 31, 2018	643,187	920	644,107
Depletion and depreciation	166,049	263	166,312
Disposals	(1,047)	–	(1,047)
Impairment (note 8)	68,000	–	68,000
Balance at December 31, 2019	\$876,189	\$1,183	\$877,372
Carrying amounts:			
At December 31, 2018	\$1,214,968	\$665	\$1,215,633
At December 31, 2019	\$1,200,138	\$812	\$1,200,950

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(a) Security:

At December 31, 2019 and 2018, all of the Company's properties were pledged as security for the bank debt (note 18).

(b) Contingencies:

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

(c) Dispositions:

For the year ended December 31, 2019 the Company disposed of its interest in one non-core property for interest in undeveloped land and recorded a gain of \$27. For the year ended December 31, 2018 the Company disposed of its interest in certain oil and gas infrastructure for \$9,778 and one non-core, non-producing property for \$111 for total proceeds of \$9,889 and recorded a gain of \$1,085.

(d) Other:

The calculation of depletion at December 31, 2019 includes estimated future development costs of \$700,604 (December 31, 2018 – \$692,356) associated with the development of the Company's proved plus probable reserves and excludes salvage value of \$70,791 (December 31, 2018 – \$57,813).

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

(\$ thousands)	Processing facilities	Surface leases	Total
As at January 1, 2019	\$35,326	\$1,910	\$37,236
Exercise of purchase option (note 12)	(22,568)	-	(22,568)
Depletion and depreciation	(2,529)	(174)	(2,703)
Impairment (note 8)	(827)	-	(827)
Balance at December 31, 2019	\$9,402	\$1,736	\$11,138

### 8. Impairment:

(a) 2019 assessment:

Impairment of \$68,000 was recorded as at December 31, 2019 as a result of a decrease in current and forecast natural gas and NGL prices. The impairment recognized relates to the Company's Cardium 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, 2019, net of decommissioning obligations, was estimated to be \$273.7 million 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 10% to 20% (level 3 inputs). The recoverable amounts of the Cardium CGU 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 lower natural gas and NGL prices. The impairment of

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\$68,000 was allocated to property, plant and equipment in the amount \$67,173 and \$827 was allocated to the right-of-use asset.

The results of Tamarack's impairment tests are sensitive to changes in: quantities of reserves and future production; forward commodity pricing as forecasted by three independent reservoir engineering companies; development costs; operating costs; royalty obligations; abandonment costs; and discount rates. As such, any changes to these key estimates could decrease or increase the recoverable amounts of assets and result in impairment charges or in the reversal of previously recorded impairment charges. As at December 31, 2019, all else being equal, a 1% change in the discount rate would result in a change to impairment of approximately \$14.5 million to the Cardium Oil CGU, a \$1.00/bbl Cdn change to oil prices would result in a change to impairment of approximately \$5.8 million to the Cardium Oil CGU, and a \$0.10/MMbtu Cdn change to gas prices would result in a change to impairment of approximately \$7.0 million to the Cardium Oil CGU. The following benchmark reference price estimates were used in determining whether an impairment or reversal to the carrying value of the CGUs existed at December 31, 2019, as forecasted by the independent external reserves evaluator based on an average of those used by three independent reservoir engineering companies:

	2020	2021	2022	2023	2024	2025	2026	2027	Thereafter
Exchange rate (US\$/Cdn\$ <sup>(1)</sup> )	0.7600	0.7700	0.7850	0.7850	0.7850	0.7850	0.7850	0.7850	0.7850
WTI (US\$/bbl) <sup>(1)</sup>	61.00	63.75	66.18	67.91	69.48	71.07	72.68	74.24	+2.0%/yr
Edmonton Par (Cdn\$/bbl) <sup>(1)</sup>	72.64	76.06	78.35	80.71	82.64	84.60	86.57	88.49	+2.0%/yr
AECO (Cdn\$/MMbtu) <sup>(1)</sup>	2.04	2.32	2.62	2.71	2.81	2.89	2.96	3.03	+2.0%/yr

(1) Price forecast, effective January 1, 2020.

(b) 2018 assessment:

Impairment (net of recovery) of \$5,000 was recorded as at December 31, 2018 as a result of a decrease in current and forecast natural gas prices. The impairment recognized relates to the Company's Cardium Oil (\$58,000) 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, net of decommissioning obligations, was estimated to be \$330.0 million 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% (level 3 inputs). During the years of 2014 and 2015, the Viking Oil CGU was tested for impairment due to decreased oil prices which resulted in the recognition of impairments in the amount of \$74,040. As a result of increased reserves and a reduction in future drilling costs per well the Company recognized an impairment reversal in the Viking Oil CGU in the amount of \$53,000. The recoverable amount of the Viking Oil CGU as at December 31, 2018, net of decommissioning obligations, was estimated to be \$110.0 million 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

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rates specific to the underlying composition of reserve categories of 8% to 15% (level 3 inputs). The recoverable amounts of the Viking Oil and Cardium Oil 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 in the volatility of oil differentials and lower natural gas prices.

The results of Tamarack's impairment tests are sensitive to changes in: quantities of reserves and future production; forward commodity pricing as forecasted by three independent reservoir engineering companies; development costs; operating costs; royalty obligations; abandonment costs; and discount rates. As such, any changes to these key estimates could decrease or increase the recoverable amounts of assets and result in impairment charges or in the reversal of previously recorded impairment charges. As at December 31, 2018, all else being equal, a 1% change in the discount rate would result in a change to impairment of approximately \$15.0 million to the Cardium Oil CGU and a \$5.0 million change to the impairment reversal of the Viking Oil CGU while a \$1.00/bbl Cdn change to oil prices would result in a change to impairment of approximately \$5.6 million to the Cardium Oil CGU and a \$3.4 million change to the impairment reversal of the Viking Oil CGU. The following benchmark reference price estimates were used in determining whether an impairment or reversal to the carrying value of the CGUs existed at December 31, 2018, as forecasted by the independent external reserves evaluator based on an average of those used by three independent reservoir engineering companies:

	2019	2020	2021	2022	2023	2024	2025	2026	Thereafter
Exchange rate (US\$/Cdn\$ <sup>(1)</sup> )	0.7567	0.7817	0.7967	0.8033	0.8067	0.8083	0.8083	0.8083	0.8083
WTI (US\$/bbl) <sup>(1)</sup>	58.58	64.60	68.20	71.00	72.81	74.59	76.42	78.40	+2.0%/yr
Edmonton Par (Cdn\$/bbl) <sup>(1)</sup>	67.30	75.84	80.17	83.22	85.34	87.33	89.50	91.89	+2.0%/yr
AECO (Cdn\$/MMbtu) <sup>(1)</sup>	1.88	2.31	2.74	3.05	3.21	3.31	3.39	3.46	+2.0%/yr

(1) Price forecast, effective January 1, 2019.

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### 9. Exploration and evaluation assets:

(\$ thousands)	Total
Cost:	
Balance at January 1, 2018	\$23,968
Additions	2,932
Transfer to property, plant and equipment (note 7)	(894)
Balance at December 31, 2018	26,006
Additions	(122)
Transfer to property, plant and equipment (note 7)	(30)
Balance at December 31, 2019	\$25,854
Accumulated amortization and impairment:	
Balance at January 1, 2018	\$22,140
Amortization	1,078
Balance at December 31, 2018	23,218
Amortization	999
Balance at December 31, 2019	\$24,217
	Total
Carrying amounts:	
At December 31, 2018	\$2,788
At December 31, 2019	\$1,637

E&E assets consist of the Company's exploration projects which are pending the determination of proven or probable reserves. Additions represent the Company's share of costs incurred on E&E assets during the period.

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### 10. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted and uninflated amount of cash flows required to settle its decommissioning obligations to be approximately \$195.6 million at December 31, 2019 (December 31, 2018 – \$191.3 million), which is expected to be incurred between 2020 and 2041. A risk-free rate of 1.8% (December 31, 2018 – 2.3%) and an inflation rate of 1.4% (December 31, 2018 – 2%) is used to calculate the present value of the decommissioning obligations at December 31, 2019 as presented in the table below:

(\$ thousands)	December 31, 2019	December 31, 2018
Balance, beginning of the year	\$193,003	\$177,793
Liabilities incurred	12,031	13,379
Change in estimates	(20,750)	–
Expenditures	(3,154)	(1,901)
Liabilities disposed	(359)	(374)
Accretion	4,075	4,106
Balance, end of the year	\$184,846	\$193,003

The change in estimate for the year ended December 31, 2019 resulted from the decommissioning obligations being revalued using a different risk-free rate and inflation rate at December 31, 2019 than that used at December 31, 2018.

### 11. Personnel expenses:

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

Years ended December 31, (\$ thousands)	2019	2018
Wages and salaries	\$9,104	\$8,443
Benefits and other personnel costs	1,592	1,650
Stock-based compensation	11,384	11,797
Total employee remuneration	22,080	21,890
Capitalized portion of total remuneration	(6,226)	(7,277)
	\$15,854	\$14,613

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

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

Years ended December 31, (\$ thousands)	2019	2018
Salaries, wages and short-term benefits	\$4,674	\$4,254
Stock-based compensation <sup>(1)</sup>	7,056	5,857
	<b>\$11,730</b>	<b>\$10,111</b>

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

### 12. Lease liabilities:

The Company has lease liabilities for contracts related to financing facilities and surface leases. Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. Discount rates used during the year ended December 31, 2019 were between 4.5% and 8.8%, depending on the duration of the lease term with a weighted average incremental borrowing rate of 5.6%. The following table summarizes lease liabilities at December 31, 2019:

(\$ thousands)	December 31, 2019
Balance, beginning of the year	\$37,236
Interest expense	1,241
Lease payments	(3,979)
Exercise of purchase option <sup>(1)</sup>	(22,328)
Balance, end of the year	\$12,170
Current portion	\$2,209
Long term portion	\$9,961

<sup>(1)</sup> The Company exercised an option right to purchase a leased asset which is now included in property, plant and equipment.

Undiscounted cash outflows relating to the lease liabilities are:

(\$ thousands)	As at December 31, 2019
Less than 1 year	\$3,043
Years 2 and 3	6,076
Years 4 and 5	4,582
Thereafter	3,855
Total	\$17,556

The expense recognized relating to short-term leases and leases of low-value assets for the year-ended December 31, 2019 was \$0.1 million and has been included in production expenses.

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### 13. Supplemental cash flow information:

Changes in non-cash working capital consists of:

(\$ thousands)	Years ended December 31,	
	2019	2018
Source/(use) of cash:		
Accounts receivable	<b>\$(21,008)</b>	\$17,462
Prepaid expenses and deposits	<b>446</b>	725
Accounts payable and accrued liabilities	<b>(4,157)</b>	(9,093)
	<b>\$(24,719)</b>	\$9,094
Related to operating activities	<b>\$(11,049)</b>	\$12,098
Related to investing activities	<b>\$(13,670)</b>	\$(3,004)

The following are included in cash flows from operating activities:

(\$ thousands)	Years ended December 31,	
	2019	2018
Interest paid in cash on bank debt	<b>\$7,573</b>	\$7,681
Bank renewal fees	<b>631</b>	391
Interest paid on lease liabilities	<b>1,241</b>	–

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

(\$ thousands)	Lease liabilities	Bank debt
Balance at January 1, 2018:	<b>\$–</b>	\$163,889
<i>Changes from financing cash flows:</i>		
Repayment of bank debt	–	(2,394)
Balance at December 31, 2018	<b>\$–</b>	\$161,495
<i>Changes from financing cash flows:</i>		
Payment of lease liabilities	<b>(2,738)</b>	–
Purchase of leased asset	<b>(22,328)</b>	–
Draw on bank debt	–	34,271
<i>Other changes:</i>		
IFRS 16 adoption	<b>37,236</b>	–
Interest expense	<b>1,241</b>	–
Interest paid	<b>(1,241)</b>	–
Unrealized gain on foreign exchange	–	(2,859)
Balance at December 31, 2019	<b>\$12,170</b>	\$192,907

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### 14. Income taxes:

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

Years ended December 31, (\$ thousands)	2019	2018
Income (loss) before taxes	<b>\$(53,409)</b>	\$59,142
Expected tax rate	<b>26.53%</b>	27.00%
Expected income tax expense (recovery)	<b>(14,169)</b>	15,968
Change in unrecognized deferred tax assets	<b>(177)</b>	101
Stock-based compensation	<b>2,570</b>	2,396
Change in rates and other	<b>(2,622)</b>	2,367
Deferred income tax expense (recovery)	<b>\$(14,398)</b>	\$20,832

In 2019, the blended statutory tax rate was 26.53% (December 31, 2018 – 27.00%). In the second quarter of 2019, the Alberta government enacted a decrease in the Alberta corporate income tax rate from 12% to 11% effective July 1, 2019, with a further reduction of 1% on January 1 for each of the years 2020, 2021 and 2022 bringing the provincial rate to 8%. As a result, the Company revalued its deferred income tax balances, resulting in a deferred income tax recovery of \$4.3 million.

Deferred tax assets and liabilities are attributable to the following:

Years ended December 31, (\$ thousands)	2019	2018
Deferred tax liabilities:		
Property, plant and equipment	<b>\$(126,622)</b>	\$(139,706)
Financial instruments and foreign exchange	-	(5,308)
Deferred tax assets:		
Financial instruments and foreign exchange	<b>992</b>	-
Non-capital losses	<b>39,797</b>	37,795
Share issue costs	<b>320</b>	2,480
Lease obligations	<b>2,921</b>	-
Decommissioning obligations	<b>44,363</b>	52,112
Total	<b>\$(38,229)</b>	\$(52,627)

In calculating the deferred income tax liability in 2019, the Company included \$165.8 million (December 31, 2018 - \$140.5 million) of non-capital losses available for carry forward to reduce taxable income in future years. These losses expire between 2029 and 2039.

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

Years ended December 31, (\$ thousands)	2019	2018
Property, plant and equipment	<b>\$18,615</b>	\$17,202

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

(\$ thousands)	Balance January 1, 2018	Recognized in equity	Recognized in business combinations	Recognized in profit or loss	Other	Balance December 31, 2018
Property, plant and equipment	\$(129,868)	\$ –	\$ –	\$(5,194)	\$ –	\$(135,062)
Non-capital losses	50,580	–	–	(12,785)	–	37,795
Decommissioning obligations	47,547	–	–	4,565	–	52,112
Share issue costs	2,469	–	–	11	–	2,480
Unrecognized deferred tax assets	(4,543)	–	–	(101)	–	(4,644)
Financial instruments and foreign exchange	2,020	–	–	(7,328)	–	(5,308)
<b>Total</b>	<b>\$(31,795)</b>	<b>\$ –</b>	<b>\$ –</b>	<b>\$(20,832)</b>	<b>\$ –</b>	<b>\$(52,627)</b>

(\$ thousands)	Balance January 1, 2019	Recognized in equity	Recognized in business combinations	Recognized in profit or loss	Other	Balance December 31, 2019
Property, plant and equipment	\$(135,062)	\$ –	\$ –	\$12,907	\$ –	\$(122,155)
Lease liabilities	–	–	–	2,921	–	2,921
Non-capital losses	37,795	–	–	2,002	–	39,797
Decommissioning obligations	52,112	–	–	(7,749)	–	44,363
Share issue costs	2,480	–	–	(2,160)	–	320
Unrecognized deferred tax assets	(4,644)	–	–	177	–	(4,467)
Financial instruments and foreign exchange	(5,308)	–	–	6,300	–	992
<b>Total</b>	<b>\$(52,627)</b>	<b>\$ –</b>	<b>\$ –</b>	<b>\$14,398</b>	<b>\$ –</b>	<b>\$(38,229)</b>

### 15. Finance expenses:

(\$ thousands)	Years ended December 31,	
	2019	2018
Interest on bank debt	<b>\$8,204</b>	\$8,072
Interest expense on lease liabilities	<b>1,241</b>	–
Unrealized gain on foreign exchange	<b>(2,859)</b>	–
Unrealized loss on cross-currency swaps	<b>2,908</b>	–
Accretion of decommissioning obligations	<b>4,075</b>	4,106
	<b>\$13,569</b>	\$12,178

The Company manages its credit facility using a combination of bankers' acceptance loans and US dollar denominated London Inter-bank Offered Rate ("LIBOR") loans. During the year ended December 31, 2019, concurrent with the drawdown of US dollar LIBOR loans, the Corporation entered into cross-currency swaps ("CCS") to fix the foreign exchange on US dollar LIBOR loan amounts for purposes of

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interest and principal repayments. At December 31, 2019, the Corporation had drawn US\$141.0 million, fixed at notional amounts of \$185.9 million through various CCS.

### 16. Shareholders' equity:

#### a) Share capital:

At December 31, 2019 and 2018 the Company was authorized to issue an unlimited number of common shares ("Common Shares") and preferred shares without nominal or par value. At December 31, 2019, Tamarack had issued and outstanding 222,793,117 Common Shares (December 31, 2018 - 226,072,693). No preferred shares have been issued.

#### 2019:

During the year ended December 31, 2019 the Company settled 231,000 restricted share units ("RSUs") by issuing 163,000 Common Shares and a payment of \$0.2 million for withholding tax on behalf of the employee in exchange for the remaining balance of 68,000 RSUs.

#### 2018:

During the year ended December 31, 2018, 1.7 million stock options at an average price of \$3.23 per share were exercised for gross proceeds of \$5.4 million. There were also 98,000 RSUs converted to common shares.

#### b) Normal course issuer bid:

On April 4, 2019, the Company announced that the Toronto Stock Exchange had accepted the Company's intention to commence a normal course issuer bid ("NCIB"). Pursuant to the NCIB, the Company is permitted to purchase up to 8.6 million Common Shares between April 8, 2019 and April 7, 2020. During the year ended December 31, 2019, the Company purchased and cancelled 4.2 million Common Shares at an average price of \$1.98 per Common Share, for a total repurchase cost of \$8.3 million.

On April 4, 2018, the Company announced that the Toronto Stock Exchange had accepted the Company's intention to commence a NCIB. Pursuant to the NCIB, the Company is permitted to purchase up to 8.6 million Common Shares of the Company between April 6, 2018 and April 5, 2019. During the year ended December 31, 2018, the Company repurchased 3.0 million Common Shares at an average price of \$3.87 per Common Share, for a total repurchase cost of \$11.7 million.

#### c) Treasury shares:

During the year ended December 31, 2019, the Company spent \$3.5 million to purchase 1.6 million Common Shares to be used to settle RSUs on the date of exercise. As at December 31, 2019, 469,120 Common Shares remain classified as treasury shares to be used for future settlements.

During the year ended December 31, 2018, the Company spent \$5.8 million to purchase 1.8 million Common Shares to be used to settle RSUs on the date of exercise. As at December 31, 2018, 1,162,789 Common Shares remain classified as treasury shares to be used for future settlements.

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### 17. Income (loss) per share:

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

	Years ended December 31,	
(\$ thousands, except per share amounts)	2019	2018
Net income (loss)	<b>\$(39,011)</b>	\$38,310
Weighted average shares - basic	<b>225,219</b>	227,720
Weighted average shares - diluted	<b>225,219</b>	233,561
Net income (loss) per share-basic	<b>\$(0.17)</b>	\$ 0.17
Net income (loss) per share-diluted	<b>\$(0.17)</b>	\$ 0.16

Per share amounts have been calculated using the weighted average number of Common Shares outstanding. For the year ended December 31, 2019, 12.3 million Common Shares issuable upon the exercise and/or settlement of stock options ("Options"), RSUs, performance share units ("PSUs") and TAC Preferred Shares (as defined below) were excluded from the diluted weighted average number of Common Shares outstanding as they were anti-dilutive due to the net loss. For the year ended December 31, 2018, 10.3 million Common Shares issuable upon the exercise and/or settlement of Options, RSUs, PSUs and TAC Preferred Shares were included in the diluted weighted average number of Common Shares outstanding.

### 18. Bank debt:

The Company currently has available a revolving credit facility in the amount of \$320 million and a \$30 million operating facility (collectively, the "Facility") with a syndicate of lenders. The Facility, totaling \$350 million, lasts for a 365-day period and will be subject to its next 365-day extension by May 31, 2020. If not extended on May 31, 2020, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that date.

In November 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, 2019, 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, 2019, 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

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on the banks' 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 to be completed by May 31, 2020.

At December 31, 2019, the Company had utilized the Facility in the amount of \$192.9 million. The interest rate applicable to the drawn amounts as of this date was 3.55%. As at December 31, 2019, the Company had letter of guarantees outstanding in the amount of \$0.2 million against the Facility.

There are no financial covenants governing the Facility. Non-financial covenants include reporting requirements, permitted indebtedness, permitted hedging and other standard business operating covenants.

### 19. Share-based payments:

#### (a) Preferred share plan:

There are 1,021,974 (December 31, 2018 – 1,086,974) preferred shares of Tamarack Acquisition Corp. (the "TAC Preferred Shares") issued and outstanding. At December 31, 2019, the TAC Preferred Shares were fully vested and exchangeable into 982,667 (December 31, 2018 – 1,045,168) Common Shares at an exchange price of \$3.12 per Common Share.

Under the terms of the Company's preferred share plan, a cashless settlement alternative is available, whereby holders of TAC Preferred Shares can either (i) elect to receive Common Shares by delivering cash to the Company in the amount of the TAC Preferred Shares, or (ii) elect to receive a number of Common Shares equivalent to the market value of the TAC Preferred Shares in excess of the TAC Preferred Shares at the exchange price of \$3.12 per Common Share. For the year ended December 31, 2019 no TAC Preferred Shares were exchanged and 65,000 TAC Preferred Shares were forfeited.

#### (b) Options:

Pursuant to the Company's stock option plan (the "Stock Option Plan") and the Company's performance and restricted share unit plan (the "PRSU Plan"), the Company may grant up to an aggregate of 15.6 million Options, RSUs and PSUs to officers, employees, directors and consultants of the Company or its subsidiaries, as applicable. As at December 31, 2019, there was an aggregate of 11.3 million Options, RSUs and PSUs issued and outstanding.

Options issued under the Stock Option Plan do not have an exercise price of less than the market price of the Common Shares at the time of grant, do not exceed a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were 390,000 Options granted during the year ended December 31, 2019.

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The fair value of each Option granted during the years ended December 31, 2019 and 2018 was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value and weighted average assumptions used to fair value the options are as follows:

	2019	2018
Risk free rate (%)	1.59	1.94
Expected volatility (%)	80	80
Expected life (years)	5	5
Forfeiture rate (%)	–	–
Dividend (\$ per share)	–	–
Fair value at grant date (\$ per option)	1.65	1.78

The number and weighted average exercise prices of the Options are as follows:

	Number of Options (thousands)	Weighted average exercise price
Outstanding, January 1, 2018	4,556	\$3.79
Granted	195	2.62
Exercised	(1,682)	3.23
Expired	(124)	5.68
Outstanding, December 31, 2018	2,945	\$3.95
Granted	390	2.57
Exercised	(15)	2.75
Expired	(1,127)	5.32
<b>Outstanding, December 31, 2019</b>	<b>2,193</b>	<b>\$3.01</b>

The range of exercise prices of the Options outstanding and exercisable at December 31, 2019 is as follows:

Range of exercise price	Options outstanding			Options exercisable	
	Number outstanding (thousands)	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable (thousands)	Weighted average exercise price
\$ 2.57 – 3.00	1,271	\$2.67	2.4	722	\$2.72
\$ 3.01 – 4.15	922	\$3.48	1.9	905	\$3.48
<b>\$ 2.57 – 4.15</b>	<b>2,193</b>	<b>\$3.01</b>	<b>2.1</b>	<b>1,627</b>	<b>\$3.14</b>

### (c) RSUs:

The PRSU Plan allows the Board of Directors to grant RSUs to officers, employees, consultants and non-employee directors of the Company or its subsidiaries. Each RSU entitles the holder to an award value to be paid as to one-third on each of the first, second and third anniversaries of the date of grant. There were 2.5 million RSUs granted during the year ended December 31, 2019 (December 31, 2018 – 2.4 million).

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

The following table summarizes information about the RSU:

	Number of RSU (thousands)
Outstanding, January 1, 2018	5,818
Granted	2,378
Exercised	(709)
Forfeited	(80)
Outstanding, December 31, 2018	7,407
Granted	2,533
Exercised	(2,596)
Forfeited	(357)
<b>Outstanding, December 31, 2019</b>	<b>6,987</b>
<b>Exercisable, December 31, 2019</b>	<b>2,709</b>

(d) PSUs:

The PRSU Plan allows the Board of Directors to grant PSU awards to officers, employees and consultants of the Company or its subsidiaries. Each PSU entitles the holder to an award value on the third anniversary of the date of grant multiplied by a payout multiplier ranging from 0 to 2.0 times. The payout multiplier for performance-based awards will be determined by the Board of Directors based on an assessment of the Company's achievement of predefined corporate performance measures in respect of the applicable period. There were 1.2 million PSUs granted during the year ended December 31, 2019 (December 31, 2018 – 1.0 million).

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

The following table summarizes information about the PSU awards:

	Number of PSU awards (thousands)
Outstanding, January 1, 2018	–
Awarded	983
Outstanding, December 31, 2018	983
Awarded	1,211
Forfeited	(37)
<b>Outstanding, December 31, 2019</b>	<b>2,157</b>
<b>Earned, December 31, 2019</b>	<b>237</b>
<b>Exercisable, December 31, 2019</b>	<b>–</b>

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### 20. Commitments:

On January 1, 2019, the Company adopted IFRS 16 which resulted in the recognition of lease liabilities related to operating leases for facilities on the balance sheet. These liabilities were previously reported as commitments. The following table summarizes the Company's commitments as at December 31, 2019:

(\$ thousands)	2020	2021	2022	2023	2024	2025+
Office lease <sup>(1)</sup>	263	–	–	–	–	–
Take or pay commitments <sup>(2)</sup>	2,256	2,294	2,340	2,396	–	–
Gas transportation <sup>(3)</sup>	229	76	–	–	–	–
Total	2,748	2,370	2,340	2,396	–	–

(1) Relates to the operating costs for the office lease which are a non-lease component of lease liabilities. For the year ended December 31, 2019, \$0.5 million of operating costs have been included within general and administrative expenses.

(2) Pipeline commitment to deliver a minimum of 636 m<sup>3</sup>/d of crude oil/condensate subject to a take-or-pay provision of \$9.00/m<sup>3</sup>. The term starts on January 1, 2019 and lasts for 60 months.

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

Rental fees, which were in the December 31, 2018 commitments table, were removed due to the adoption of IFRS 16 (refer to note 3(m)).

### 21. Contingency:

During 2019, the Company was served with a Statement of Claim from two joint interest owners that hold minority interests in a Unit, which is majority owned and operated by the Company. The plaintiffs are seeking judgment in the amount of \$56.0 million for unlawful conversion of their minority Unit interests (such amount based upon the alleged value of their minority Unit interests) or alternatively, judgment in the amount of \$1.65 million, representing the amounts allegedly owed by the Company plus punitive damages, interest and other costs. The minority Unit owners have also alleged the Company has breached its fiduciary duties owing to the minority Unit owners and that without the approval of the minority Unit owners, the Company has conducted operations within the Unit area and outside of the Unit area without the approval of the minority Unit owners.

The Company has filed a Statement of Defence denying all material allegations of the minority Unit owners. The Company believes the claims are without merit and the amounts are unsubstantiated. Therefore, no provision for any amount has been recorded in these consolidated financial statements.

# CORPORATE INFORMATION

## Directors

Floyd Price - Chairman<sup>(3)</sup>

David MacKenzie<sup>(1)(2)</sup>

Jeff Boyce<sup>(1)(2)</sup>

Noralee Bradley<sup>(3)(4)</sup>

John Leach<sup>(1)(3)</sup>

Ian Currie<sup>(2)(4)</sup>

Rob Spitzer<sup>(3)(4)</sup>

Brian Schmidt

- (1) Member of the Audit Committee of the Board of Directors
- (2) Member of the Reserves Committee of the Board of Directors
- (3) Member of the Compensation & Governance Committee of the Board of Directors
- (4) Member of the Health, Safety & Environmental Committee of the Board of Directors

## Management Team

Brian Schmidt  
*President & Chief Executive Officer*

June-Marie Innes  
*Interim Chief Financial Officer*

Dave Christensen  
*VP Engineering*

Ken Cruikshank  
*VP Land*

Martin Malek  
*VP Corporate Planning & Business Development*

Kevin Screen  
*VP Production & Operations*

Scott Reimond  
*VP Exploration*

Sony Gill  
*Corporate Secretary*

## Lead Bank Syndicate

National Bank of Canada

## Legal Counsel

Stikeman Elliott LLP

## Auditor

KPMG LLP

## Stock Exchange

Toronto Stock Exchange  
Stock symbol: TVE

## Contact Information

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