MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the years ended December 31, 2017 and 2016. This MD&A is dated and based on information available on March 5, 2018 and should be read in conjunction with the audited consolidated financial statements and notes for the years ended December 31, 2017 and 2016. Additional information relating to Tamarack, including Tamarack's Annual Information Form, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The Company uses certain non-IFRS measures in this MD&A. For a discussion of those measures, including the method of calculation, please refer to the section titled "Non-IFRS Measures" beginning on page 18. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

Q4 2017 Financial and Operating Highlights

- Achieved record corporate production in Q4/17 of 22,807 boe/d, up 11% over volumes in Q3/17 of 20,541 boe/d and up 99% over Q4/16 volumes of 11,453 boe/d.
- Oil and natural gas liquids ("NGL") weighting was 62% in Q4/17 compared to 55% in the same period of 2016, an increase of 13%, which positively contributed to the Company's stronger netbacks year-over-year.
- Total adjusted funds flow increased 66% to $57.6 million in Q4/17 ($0.25/share basic and diluted), from $34.8 million in Q3/17 ($0.15/share basic and diluted).
- Operating netback in Q4/17 increased by 44% over Q3/17 primarily due to the 13% increase in oil and NGL weighting and the 24% increase in the combined average realized prices for oil and NGL.
- Production and transportation expenses in Q4/17 were 8% lower at $10.40/boe compared to Q3/17 and were 15% lower than Q4/16.
- Net debt at December 31, 2017 was reduced by $21.7 million or 11% quarter-over-quarter, resulting in net debt to annualized Q4/17 adjusted funds flow strengthening to 0.8 times, compared to 1.4 times at the end of Q3/17.

Transformative Business Combination Expands Viking Oil Assets

On January 11, 2017, Tamarack closed the acquisition of all of the issued and outstanding common shares of Spur Resources Ltd. ("Spur"), which held Spur's Viking oil assets at closing (the "Viking Acquisition"). Pursuant to the Viking Acquisition, the Company issued an aggregate of 90.1 million common shares of Tamarack and paid $57.8 million in cash. Tamarack also assumed Spur's net debt, estimated to be $23.6 million as at closing, after accounting for proceeds from the exercise of all outstanding options of Spur, including severance and transaction costs. Based upon Tamarack's share price at closing of $3.44 per share, the total consideration paid by Tamarack, including the assumption of debt, was approximately $392 million. The Viking Acquisition had a materially positive impact on Tamarack's results for the year ending December 31, 2017 and contributed to the Company's strong operating and financial position entering 2018.

Subsequent to closing the transformative Viking Acquisition, Tamarack integrated the assets into its existing operations and began development. The Company spent $92.7 million in 2017, drilling 104 (99 net) Viking oil wells and increasing capacity at owned facilities in both Veteran and Milton. The Company averaged 7,186 boe/d from the Viking Acquisition during 2017 and averaged 9,044 boe/d in Q4/17. Overall results from that development program met the expectations of the Company at the time of the acquisition.

Production

Quarter-over-Quarter

	Q4 2017	Q3 2017	% change
Production			
Light oil (bbls/d)	**12,189**	10,108	21
Heavy oil (bbls/d)	**500**	603	(17)
Natural gas liquids (bbls/d)	**1,459**	1,499	(3)
Natural gas (mcf/d)	**51,956**	49,987	4
Total (boe/d)	**22,807**	20,541	11
Percentage of oil and natural gas liquids	**62%**	59%	**5**

Average production for the fourth quarter of 2017 increased 11% over the previous quarter and was positively impacted by the fourth quarter drilling program and a full quarter of production from the Company's third quarter drilling program. This contributed an additional 1,393 boe/d from Wilson Creek/Alder Flats (90% oil and NGL) and 2,513 boe/d from the Viking development program (85% oil and NGL). These gains were partially offset by expected declines from legacy volumes.

The Company's oil and NGL weighting increased by 5% in the fourth quarter of 2017 compared to the third quarter of 2017, attributable to the higher oil-weighted drilling program in the Veteran and Wilson Creek areas of Alberta. In 2018, the Company expects its oil and NGL weighting to increase further and range between 64% - 67%. The weighting will ultimately depend on the timing of production additions from the higher oil-weighted areas of Wilson Creek, Penny and the Viking Acquisition assets, and additions from the higher natural gas-weighted area of Alder Flats.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
	2017	2016	% change	**2017**	2016	% change
Production						
Light oil (bbls/d)	**12,189**	4,858	151	**9,929**	4,215	136
Heavy oil (bbls/d)	**500**	316	58	**511**	363	41
Natural gas liquids (bbls/d)	**1,459**	1,075	36	**1,547**	1,035	49
Natural gas (mcf/d)	**51,956**	31,226	66	**48,893**	28,388	72
Total (boe/d)	**22,807**	11,453	99	**20,136**	10,344	95
Percentage of oil and natural gas liquids	**62%**	55%	**13**	**60%**	54%	**11**

Compared to the prior year, average fourth quarter 2017 production increased by 99% while full year production increased 95% compared to the same periods in 2016. These increases are attributable to the successful drilling programs in 2016 and 2017, as well as the impact of production from assets acquired in the Viking Acquisition and the Penny, Redwater and Wilson Creek areas (the “Penny and Redwater Acquisitions”) in July of 2016, partially offset by expected production declines from legacy assets.

Petroleum and Natural Gas Sales

Quarter-over-Quarter

	Q4 2017	Q3 2017	% change
Revenue ($ thousands)			
Oil and NGL	**$81,139**	$56,493	44
Natural gas	**9,021**	7,434	21
Total	**$90,160**	$63,927	41
Average realized price			
Light oil ($/bbl)	**65.08**	53.43	22
Heavy oil ($/bbl)	**48.97**	46.26	6
Natural gas liquids ($/bbl)	**44.03**	30.76	43
Combined average oil and NGL ($/boe)	**62.34**	50.29	24
Natural gas ($/mcf)	**1.89**	1.62	17
Revenue ($/boe)	**42.97**	33.83	27
Benchmark pricing:			
West Texas Intermediate (US$/bbl)	**55.39**	48.46	14
Edmonton Par (Cdn$/bbl)	**66.86**	57.03	17
Hardisty Heavy (Cdn$/bbl)	**48.69**	47.20	3
AECO daily index (Cdn$/mcf)	**1.68**	1.45	16
AECO monthly index (Cdn$/mcf)	**1.95**	2.03	(4)

Revenue from oil, natural gas and NGL sales was 41% higher in the fourth quarter of 2017 compared to the third quarter of 2017. Stronger revenue quarter-over-quarter is attributable to the increase in production volumes, a higher oil weighting and increased pricing for crude oil, NGL and natural gas.

WTI crude oil markets demonstrated rapid price expansion during the fourth quarter of 2017 and into 2018, after three quarters of weaker prices earlier in 2017. The average fourth quarter WTI price of US$55.39/bbl was 14% higher than the average third quarter price of US$48.46/bbl and 9% higher than the 2017 full year average price of US$51.00/bbl. Tamarack's realized light oil price for the three months ended December 31, 2017 increased 22% to $65.08/bbl from $53.43/bbl in the previous quarter. Through the fourth quarter, the WTI to Edmonton Par differential remained narrow, averaging US$1.15/bbl, which when combined with a weaker Canadian dollar, benefited the Edmonton Par Canadian price per barrel. Subsequent to year end, the WTI to Edmonton Par differential increased significantly while the Canadian dollar strengthened relative to the US dollar. Should this situation remain, the combined impact is expected to erode the value of the Edmonton Par Benchmark price in future quarters.

NGL prices increased 43% in the fourth quarter to $44.03/bbl from $30.76/bbl in the third quarter of 2017. Quarter over quarter improvements are due largely to two factors: the continued increase in propane prices through 2017 and the significant increase in WTI pricing during the fourth quarter. As most of the Company's NGL are priced relative to WTI, an increase in WTI results in an increase in butane and condensate prices. Market conditions for propane improved due to increased Gulf coast exports, higher petrochemical and winter demand and lower inventories relative to historical norms. Propane sales also positively contributed to the higher realized NGL prices per bbl. NGL contracts are generally negotiated annually, with new contracts taking effect on April 1. Realized NGL prices improved in 2017 despite a decreasing Edmonton Par benchmark due to more competitive contract terms. New contracts under current negotiations will be in effect for April 1, 2018 and we expect to continue to show competitive terms for the second quarter of 2018.

Tamarack's fourth quarter 2017 realized natural gas prices increased 17% to $1.89/mcf compared to $1.62/mcf in the previous quarter, reflecting the 16% increase in the AECO daily index natural gas price benchmark over the same period. Historically, a large portion of Tamarack's gas was priced relative to the AECO Daily index and generally correlated to this index. However, during the third quarter of 2017, Tamarack implemented a new strategy designed to diversify the Company's exposure away from the localized AECO index with exposure to other indices and markets which may have higher pricing. As a result, Tamarack's realized gas price may not correlate with the AECO daily or monthly indices going forward. The Company's gas market exposure as at December 31, 2017 was as follows:

Gas Market	**Percentage Exposure (as at December 31, 2017)**	**Percentage Exposure (as at April 1, 2018)[1]**
AECO Daily (5A)	18.5	40.3
AECO Monthly (7A)	0.0	0.0
AECO Daily (5A) + premium (SK)	26.0	19.3
Dawn	4.1	8.1
Chicago	4.1	8.1
Michigan City Gate	4.1	8.1
Malin	4.1	16.1
Financial Fixed Price (Hedged)	39.1	0.0
	100%	100%

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

While prices were expected to improve through the fourth quarter of 2017 due to typical winter weather-related demand, continued over supply in the province combined with restrictions on takeaway capacity and mild temperatures through most of the quarter resulted in smaller than expected gains. The Company expects the volatility experienced in the AECO daily index that began in the summer of 2017 to persist through 2018 and beyond. During the fourth quarter of 2017, Tamarack entered into an additional gas sales contract with a third party, commencing April 1, 2018, which will further diversify the Company's natural gas price exposure. With the addition of this contract, approximately 40% of Tamarack's total natural gas production will be exposed to alternate US markets, including Malin, Chicago, Michigan Consolidated and Dawn daily index pricing less transportation tolls, until 2022. Tamarack will continue to explore alternatives to minimize exposure to Alberta gas market fluctuations.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
	2017	2016	% change	**2017**	2016	% change
Revenue ($ thousands)						
Oil and NGL	**$81,139**	$30,404	167	**$242,223**	$90,518	168
Natural gas	**9,021**	9,389	(4)	**41,449**	24,999	66
Total	**$90,160**	$39,793	127	**$283,672**	$115,517	146
Average realized price						
Light oil ($/bbl)	**65.08**	58.71	11	**59.42**	50.53	18
Heavy oil ($/bbl)	**48.97**	44.60	10	**46.01**	35.45	30
Natural gas liquids ($/bbl)	**44.03**	28.99	52	**32.38**	20.74	56
Combined average oil and NGL ($/boe)	**62.34**	52.88	18	**55.36**	44.06	26
Natural gas ($/mcf)	**1.89**	3.27	(42)	**2.32**	2.41	(4)
Revenue ($/boe)	**42.97**	37.76	14	**38.60**	30.51	27
Benchmark pricing:						
West Texas Intermediate (US$/bbl)	**55.39**	49.33	12	**51.00**	43.40	18
Edmonton Par (Cdn$/bbl)	**66.86**	60.76	10	**62.23**	51.76	20
Hardisty Heavy (Cdn$/bbl)	**48.69**	45.76	6	**49.42**	38.22	29
AECO daily index (Cdn$/mcf)	**1.68**	3.08	(45)	**2.14**	2.15	–
AECO monthly index (Cdn$/mcf)	**1.95**	2.80	(30)	**2.41**	2.08	16

Revenue for the three months and year ended December 31, 2017 increased by 127% and 146%, respectively, relative to the same periods in 2016 primarily due to increases in production and oil and NGL prices, partially offset by a decrease in 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 by Tamarack's Board of Directors quarterly. At December 31, 2017, the Company held derivative commodity and foreign exchange contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	500 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	Cdn $73.59
Crude oil	4,400 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	US $54.26
Crude oil	4,200 bbls/day	April 1, 2018 – June 30, 2018	WTI fixed price	US $53.74
Crude oil	3,700 bbls/day	July 1, 2018 – September 30, 2018	WTI fixed price	US $53.94
Crude oil	2,400 bbls/day	October 1, 2018 – December 31, 2018	WTI fixed price	US $53.79
Crude oil	500 bbls/day	January 1, 2019 – December 31, 2019	WTI call option	US $52.00
Natural gas	25,000 GJ/day	January 1, 2018 – March 31, 2018	AECO fixed price	Cdn $3.16
Natural gas	15,000 MMBTU/day	January 1, 2018 – March 31, 2018	AECO/Henry Hub Differential	Index - US $1.34
Foreign exchange	1,595,000 US$/month	January 1, 2018 – March 31, 2018	Exchange rate	Cdn $1.31
Foreign exchange	1,040,000 US$/month	April 1, 2018 – June 30, 2018	Exchange rate	Cdn $1.29

At December 31, 2017, the commodity contracts were fair valued with a liability of $7.5 million (December 31, 2016 – $10.7 million liability) recorded on the balance sheet. The effect of the unrealized gains was $3.5 million for the year ended December 31, 2017 (December 31, 2016 – unrealized loss of $23.2 million) compared to an unrealized loss of $13.5 million for the three months ended December 31, 2017 (December 31, 2016 – unrealized loss of $7.7 million).

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement, the realized benefit or loss is recognized in oil and natural gas revenue. At December 31, 2017, the Company held no physical commodity contracts.

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

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

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

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

Royalties

Quarter-over-Quarter

	Q4 2017	Q3 2017	% change
Royalty expenses ($ thousands)	**$8,464**	$7,043	20
$/boe	**4.03**	3.73	8
percent of sales	**9**	11	(18)

Despite higher prices, royalties as a percentage of revenue were lower in the fourth quarter of 2017 compared to the third quarter of 2017 due to prior period gas cost allowance adjustments.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
	2017	2016	% change	**2017**	2016	% change
Royalty expenses ($ thousands)	**$8,464**	$3,746	126	**$29,134**	$8,795	231
$/boe	**4.03**	3.56	13	**3.96**	2.32	71
percent of sales	**9**	9	–	**10**	8	25

Royalties as a percentage of revenue were comparable in the fourth quarter of 2017 compared to the fourth quarter of 2016.

Royalties as a percentage of revenue increased during 2017 as compared to 2016, due to the sliding scale mechanism resulting in higher royalties when commodity prices increase and the impact of the Viking Acquisition wells which have a higher rate than the corporate average. This was partially offset by a 5% new well royalty rate on wells drilled in 2017. All wells drilled after January 1, 2017 are subject to a 5% flat royalty until revenues exceed a normalized well cost allowance, which will be based on vertical well depth, lateral length (for horizontal wells) and total proppant used in the fracking of the well, after which royalty rates will range between 5% and 40%, depending on commodity prices.

The Company expects royalty rates as a percentage of revenue to remain in the 10% to 12% range for 2018, based on current pricing.

Production and Transportation Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2017**	Q3 2017	% change
Total production and transportation expenses	**$21,818**	$21,271	3
Total ($/boe)	**$10.40**	$11.26	(8)

Production and transportation expenses per boe for the fourth quarter of 2017 decreased 8% compared to the third quarter of 2017, attributable to the expanded Veteran oil battery and water handling facilities that operated for a full quarter, coupled with higher volumes allocated across fixed costs. As a result of these infrastructure expansions, water trucking and disposal costs in the Veteran area were reduced by $0.75/boe in the fourth quarter. On an absolute basis, overall costs increased in the fourth quarter of 2017 over the third quarter due to the impact of a full quarter of production additions.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2017**	2016	% change	**2017**	2016	% change
Total production and transportation expenses	**$21,818**	$12,826	70	**$82,239**	$44,067	87
Total ($/boe)	**$10.40**	$12.17	(15)	**$11.19**	$11.64	(4)

On a per boe basis, for the three months and year ended December 31, 2017, production and transportation expenses were lower compared to the same periods in 2016 due to new production being added in areas that have lower per unit production and transportation costs which decreases the overall corporate average. In addition, higher volumes across fixed costs results in lower per boe costs. On an absolute basis, production and transportation expenses increased due to the increase in production volumes over the period.

Operating Netback

Quarter-over-Quarter

($/boe)	**Q4 2017**	Q3 2017	% change
Average realized sales	**$42.97**	$33.83	27
Royalty expenses	**(4.03)**	(3.73)	8
Production and transportation expenses	**(10.40)**	(11.26)	(8)
Operating field netback	**28.54**	18.84	51
Realized commodity hedging gain	**1.53**	2.11	(27)
Operating netback	**$30.07**	$20.95	44

The Company's operating netback for the fourth quarter of 2017 increased 44% to $30.07/boe compared to the previous quarter. The increase is due to oil and NGL weighting being 13% higher, a 24% increase in the combined average realized price for oil and NGL and a 17% increase in realized natural gas prices.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($/boe)	**2017**	2016	% change	**2017**	2016	% change
Average realized sales	**$42.97**	$37.76	14	**$38.60**	$30.51	27
Royalty expenses	**(4.03)**	(3.56)	13	**(3.96)**	(2.32)	71
Production and transportation expenses	**(10.40)**	(12.17)	(15)	**(11.19)**	(11.64)	(4)
Operating field netback	**28.54**	22.03	30	**23.45**	16.55	42
Realized commodity hedging gain (loss)	**1.53**	(0.15)	1,120	**0.77**	3.25	(76)
Operating netback	**$30.07**	$21.88	37	**$24.22**	$19.80	22

Full year 2017 operating netbacks increased 22% over 2016, supported by the Company's higher weighting to oil and NGL, improved realized prices across all products, and a 4% decrease in production and transportation expenses year over year, offset by a higher royalty expense. Prior to the impact of hedging, Tamarack's 2017 operating field netback per boe was 42% higher than in 2016, reflecting the effects of higher oil weighting coupled with an improved pricing environment.

General and Administrative ("G&A") Expenses

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2017**	Q3 2017	% change
Gross costs	**$4,257**	$3,889	9
Capitalized costs and recoveries	**(842)**	(832)	1
General and administrative costs	**$3,415**	$3,057	12
Total ($/boe)	**$1.63**	$1.62	1

Gross G&A expenses increased 9% in the fourth quarter of 2017 compared to the previous quarter due to increased staffing related to the production additions, increased capital activity and year end related costs. Net G&A costs per boe remained consistent between the third and fourth quarter of 2017.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2017**	2016	% change	**2017**	2016	% change
Gross costs	**$4,257**	$2,500	70	**$15,807**	$9,470	67
Capitalized costs and recoveries	**(842)**	(510)	65	**(3,345)**	(2,075)	61
General and administrative costs	**$3,415**	$1,990	72	**$12,462**	$7,395	69
Total ($/boe)	**$1.63**	$1.89	(14)	**$1.70**	$1.95	(13)

Gross G&A costs increased in the three months and year ended December 31, 2017, compared to the same periods in 2016, due to the increase in the number of employees and increased office space stemming from the growth associated with the Viking Acquisition, coupled with an increase in production. Net G&A costs per boe in both the three months and year ended December 31, 2017 were lower than the same periods in 2016 due to costs allocated across a larger volume of production.

Stock-Based Compensation Expenses

Quarter-over-Quarter

($ thousands)	**Q4 2017**	Q3 2017	% change
Gross cost	**$1,618**	$1,541	5
Capitalized costs	**(481)**	(489)	(2)
Total share-based compensation	**$1,137**	$1,052	8

Stock-based compensation expenses related to stock options ("options") and restricted share unit awards ("RSUs") was similar in the fourth quarter of 2017 compared to the previous quarter.

Year-over-Year

($ thousands)	Three months ended December 31, 2017	2016	% change	Years ended December 31, 2017	2016	% change
Gross cost	**$1,618**	$1,169	38	**$6,357**	$5,002	27
Capitalized costs	**(481)**	(335)	44	**(1,997)**	(1,479)	35
Total share-based compensation	**$1,137**	$834	36	**$4,360**	$3,523	24

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

For the year ended December 31, 2017, the Company issued 0.1 million options at a weighted average exercise price of $3.01 per share and issued 2.8 million RSUs. Additionally, 0.8 million options at $1.98 per share were exercised for total gross proceeds of $1.6 million, while 28,000 RSUs were settled and 0.1 million options expired.

Interest Expense

Quarter-over-Quarter

($ thousands, except per boe)	Q4 2017	Q3 2017	% change
Interest on bank debt	**$2,097**	$1,776	18
Total ($/boe)	**$1.00**	$0.94	6
Average drawings on bank debt	**$175,373**	$156,057	12

Interest expense was higher in the fourth quarter of 2017 compared to the third quarter of 2017, due to a higher average amount drawn quarter-over-quarter on the revolving credit facility. The higher credit facility draw is related to increased capital for drilling and completions activities that commenced late in the third quarter and continued into the fourth quarter.

Year-over-Year

($ thousands, except per boe)	Three months ended December 31, 2017	2016	% change	Years ended December 31, 2017	2016	% change
Interest on bank debt	**$2,097**	$615	241	**$7,093**	$3,392	109
Total ($/boe)	**$1.00**	$0.58	72	**$0.97**	$0.90	8
Average drawings on bank debt	**$175,373**	$48,451	262	**$150,873**	$55,382	172

Interest expense for the three months and year ended December 31, 2017 was higher than the same periods in 2016. This is attributable to an interest rate increase that occurred during the third quarter of 2017 and to higher average amounts drawn year-over-year on the revolving credit facility related to the Viking Acquisition and increased capital for drilling and completions activities in 2017.

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

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

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2017**	Q3 2017	% change
Depletion and depreciation	**$41,569**	$38,746	7
Amortization of undeveloped leases	**197**	197	–
Accretion	**1,035**	892	16
Total	**$42,801**	$39,835	7
Depletion and depreciation ($/boe)	**$19.81**	$20.50	(3)
Amortization ($/boe)	**0.09**	0.10	(10)
Accretion ($/boe)	**0.49**	0.47	4
Total ($/boe)	**$20.39**	$21.07	(3)

For the fourth quarter of 2017, DDA&A expense per boe decreased 3% compared to the third quarter of 2017. This decrease is due to completion of the Company's year-end independent reserve evaluation which resulted in an increase in Tamarack's overall reserve base following the successful 2017 drilling program and better-than-expected well performance. On an absolute basis, DDA&A expense was higher quarter-over-quarter due to increased production despite recording lower DDA&A expense on a per boe basis.

Year-over-Year

	Three months ended December 31,			Years ended December 31,		
($ thousands, except per boe)	**2017**	2016	% change	**2017**	2016	% change
Depletion and depreciation	**$41,569**	$17,688	135	**$147,862**	$64,667	129
Amortization of undeveloped leases	**197**	203	(3)	**787**	760	4
Accretion	**1,035**	527	96	**3,741**	1,696	121
Total	**$42,801**	$18,418	132	**$152,390**	$67,123	127
Depletion and depreciation ($/boe)	**$19.81**	$16.79	18	**$20.12**	$17.08	18
Amortization ($/boe)	**0.09**	0.19	(53)	**0.11**	0.20	(45)
Accretion ($/boe)	**0.49**	0.50	(2)	**0.51**	0.45	13
Total ($/boe)	**$20.39**	$17.48	17	**$20.74**	$17.73	17

For the three months and year ended December 31, 2017, DDA&A expense per boe was higher relative to the same periods in 2016. The increase in the DDA&A rate was related primarily to the Viking Acquisition. On an absolute basis, DDA&A expense was higher for the three months and year ended December 31, 2017, due to an increase in production coupled with higher DDA&A expense on a per boe basis.

Income Taxes

The Company did not incur any cash tax expense in the three months and year ended December 31, 2017, nor does it expect to pay any cash tax in 2018 or 2019 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three months and year ended December 31, 2017, deferred income tax recovery of $4.3 million and $3.6 million, respectively, were recognized compared to a deferred income tax recovery of $0.2 million and $4.6 million for the same respective periods in 2016.

The following table outlines the Company's estimated tax pools as at December 31, 2017:

Tax Pool Category	Deduction Rate	($ millions)
Canadian exploration expense (CEE)	100%	38
Canadian development expense (CDE)	30%	299
Canadian oil and gas property expense (COGPE)	10%	249
Non-capital losses (NCL)	100%	190
Undepreciated capital cost (UCC)	25%	110
Share issue costs and other	various	9
Total		895

Adjusted Funds Flow and Net Loss

Quarter-over-Quarter

($ thousands, except per boe)	**Q4 2017**	Q3 2017	% change
Cash provided by operating activities	**$50,056**	$35,237	42
Adjusted funds flow	**$57,583**	$34,774	66
Per share - basic and diluted	**$0.25**	$0.15	67
Net loss	**$(12,525)**	$(6,742)	86
Per share - basic and diluted	**$(0.05)**	$(0.03)	67

Cash provided by operating activities and adjusted funds flow (see Non-IFRS Measures) during the fourth quarter of 2017 were higher than the third quarter of 2017. The increase in the absolute amount is primarily the result of an 11% increase in production, a 17% increase in natural gas prices and a 24% increase in oil and NGL pricing.

The Company recorded a net loss of $12.5 million ($0.05 per share basic and diluted) during the three months ended December 31, 2017, compared to a net loss of $6.7 million ($0.03 per share basic and diluted) for the previous quarter. The factors contributing to a higher net loss in the fourth quarter of 2017 compared the previous quarter included a higher unrealized hedging loss and an impairment to property, plant and equipment taken in the fourth quarter. These factors were partially offset by higher oil and natural gas revenue.

Year-over-Year

($ thousands, except per boe)	Three months ended December 31, 2017	2016	% change	Years ended December 31, 2017	2016	% change
Cash provided by operating activities	**$50,056**	$17,609	184	**$144,525**	$60,738	138
Adjusted funds flow	**$57,583**	$20,453	182	**$158,383**	$64,164	147
Per share - basic and diluted	**$0.25**	$0.15	67	**$0.70**	$0.52	35
Net loss	**$(12,525)**	$(8,425)	49	**$(13,924)**	$(27,823)	(50)
Per share - basic and diluted	**$(0.05)**	$(0.06)	(17)	**$(0.06)**	$(0.23)	(74)

Fourth quarter 2017 cash provided by operating activities and adjusted funds flow (see Non-IFRS Measures) were higher on an absolute basis than the same period in 2016, primarily due to a 99% increase in production, an 18% increase in oil and NGL pricing and a realized hedging gain in the fourth quarter of 2017 compared to a realized hedging loss in the same quarter of 2016. The year-over-year increase was partially offset by a 42% decrease in natural gas prices, a 126% increase in royalty expense, a 70% increase in production and transportation expenses and a 241% increase in interest expense.

Cash provided by operating activities and adjusted funds flow (see Non-IFRS Measures) during the year ended December 31, 2017 were higher compared to the same period in 2016. The increase is primarily due to a 95% increase in production and a 26% increase in oil and NGL pricing. The year-over-year increase was partially offset by a 231% increase in royalty expense, an 87% increase in production and transportation expenses, a 109% increase in interest expense, a 69% increase in net G&A expense and a lower realized hedging gain.

The Company recorded a net loss of $12.5 million ($0.05 per share basic and diluted) during the three months ended December 31, 2017, compared to a net loss of $8.4 million ($0.06 per share basic and diluted) for the same period in 2016. The factors contributing to a higher net loss in the fourth quarter of 2017 compared to the same period in 2016 include higher expenses for production and transportation, royalties, G&A, and DDA&A, a higher unrealized hedging loss and an impairment to property, plant and equipment taken in the fourth quarter of 2017, partially offset by higher oil and natural gas revenue.

The Company recorded a net loss of $13.9 million ($0.06 per share basic and diluted) during the year ended December 31, 2017, compared to a net loss of $27.8 million ($0.23 per share basic and diluted) for the same period in 2016. The factors contributing to a lower net loss for the year ended December 31, 2017 compared to the same period in 2016 include higher oil and natural gas revenue and an unrealized gain on financial instruments compared to an unrealized loss in 2016. These were partially offset by higher expenses for production and transportation, royalties, G&A, interest and DDA&A and an impairment to property, plant and equipment taken in the fourth quarter of 2017.

Capital Expenditures (Including Exploration and Evaluation Expenditures)

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

	Three months ended December 31,			Years ended December 31,		
($ thousand)	**2017**	2016	% change	**2017**	2016	% change
Land	**$(174)**	$603	(129)	**$1,708**	$2,092	(18)
Geological and geophysical	**–**	27	(100)	**2,022**	464	336
Drilling and completion	**26,378**	12,243	115	**143,802**	46,353	210
Equipment and facilities	**8,591**	1,730	397	**41,766**	6,588	534
Capitalized G&A	**687**	182	277	**2,670**	889	200
Office equipment	**34**	78	(56)	**334**	433	(23)
Total capital expenditures	**$35,516**	$14,863	139	**$192,302**	$56,819	238

In addition to capital directed to well completions and infrastructure projects that were started in prior quarters, Tamarack accelerated capital spending from its planned 2018 drilling program into 2017 near the end of the fourth quarter. Deploying capital in 2017 to start 2018 projects was intended to secure favorable service cost rates and ensure timely completion of first quarter activities by avoiding service sector delays that impacted the industry in the first quarter of 2017. The Company invested a total of $35.5 million in the fourth quarter resulting in a total annual capital spend of $192.3 million excluding property acquisitions, which is in line with Tamarack's adjusted guidance of $195 - $198 million provided within the third quarter financial and operating results release. Including property and tuck-in asset acquisitions net of dispositions as outlined below, Tamarack invested $198.5 million. During the fourth quarter of 2017, the Company drilled, completed and equipped three (2.3 net) Redwater oil wells and one (1.0 net) Cardium oil well. The Company also brought on production ten (10.0 net) Viking oil wells, three (3.0 net) Cardium oil wells, two (2.0 net) heavy oil wells and one (1.0 net) Penny Barons oil well, which were all drilled prior to the start of the fourth quarter. Additionally, the Company drilled 15 (14.4 net) Viking oil wells, which were fracture stimulated and brought on production in early 2018.

In addition to the Company's significant drilling and completion projects, Tamarack advanced several other capital activities during the fourth quarter designed to reduce costs and enhance the asset base. At Veteran, the Company concluded the first phase of its oil battery expansion and the installation of associated oil pipelines, which collectively are expected to significantly reduce water handling costs for the area. At Wilson Creek, the Company's purchase of a compressor will eliminate ongoing expenses associated with renting compression equipment and positively impact area production costs.

	2017 Drilling Summary		2016 Drilling Summary	
	Gross	Net	Gross	Net
Heavy Oil	5.0	5.0	2.0	2.0
Viking	104.0	99.0	2.0	2.0
Mannville	3.0	3.0	1.0	0.8
Cardium	16.0	15.3	15.0	14.4
Other	5.0	4.1	0.0	0.0
	133.0	126.4	20.0	19.2

At the end of 2017, the Company's net undeveloped land totaled 374,052 acres, an increase of 87% compared to the 245,047 net undeveloped acres held at the end of 2016.

Acquisitions

During the fourth quarter of 2017, Tamarack completed two tuck-in acquisitions totalling $6.6 million, in the Wilson Creek and Veteran areas of Alberta. Through these acquisitions the Company added 84 boe/d and 38 (30.6 net) sections of undeveloped land. During the fourth quarter the Company also completed two dispositions for proceeds of $5.0 million. The dispositions did not have any production associated with the disposed assets.

During 2017, Tamarack completed eight minor tuck-in acquisitions, besides the Viking Acquisition noted below, totalling $12 million and completed three dispositions for proceeds of $5.3 million. The acquisitions added 129 boe/d and 395 (260 net) sections of undeveloped land. The dispositions did not have any production associated with the disposed assets.

Tamarack closed the corporate acquisition of Spur Resources on January 11, 2017 and through this Viking Acquisition, significantly increased the Company's land base, reserves and production. Total consideration paid by the Company for the Viking Acquisition, including the assumption of debt, was approximately $392 million based on Tamarack's share price at closing of $3.44 per share.

The Viking Acquisition has been accounted for as a business combination using the acquisition method of accounting, whereby the assets acquired and the liabilities assumed are recorded at the estimated fair value on the acquisition date of January 11, 2017. The allocation of the purchase price is outlined in the table below:

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

The fair value of PP&E has been estimated with reference to an independently prepared reserves evaluation for the acquired properties. The fair value of decommissioning obligations was initially estimated using a credit-adjusted risk-free rate of 8% and subsequently revalued using the risk-free rate.

Impairment

An impairment charge of $17.0 million (December 31, 2016 – nil) was recorded as at December 31, 2017 on the Company's PP&E. The impairment charge is the result of a negative technical reserve revision and a decrease in current and forecast future commodity prices. The impairment recognized in 2017 relates to the Company's heavy oil ($13.0 million) and shallow gas ($4.0 million) Cash-Generating Unit ("CGU"). The recoverable amount of these CGU's as at December 31, 2017 was estimated to be $3.7 million for the heavy oil CGU and nil for the shallow gas CGU based on the net present value of before tax cash flows from proved plus probable reserves estimated by the Company at discount rates in excess of 20%. The recoverable amount of Tamarack's CGUs was estimated using the fair value less costs of disposal methodology based on what Tamarack could get for these assets if it disposed of them in the current environment taking into account the recent increase to heavy oil differentials and lower natural gas prices. As the recoverable amount of a CGU is sensitive to a decrease in commodity prices, further impairment charges could be recorded in future periods.

As at December 31, 2016 the Company recognized an exploration and evaluation impairment of $0.7 million related to the drill and abandonment of four vertical stratigraphic test wells in the Hatton area (heavy oil CGU).

Liquidity and Capital Resources

($ thousand)	**December 31, 2017**	September 30, 2017	December 31, 2016
Working capital deficiency	**$9,291**	$32,753	$7,089
Bank debt	**163,889**	162,164	45,227
Net debt	**173,180**	194,917	52,316
Quarterly adjusted funds flow	**$57,583**	$34,774	$20,453
Annualized factor	**4**	4	4
Annualized adjusted funds flow	**230,332**	139,096	81,812
Debt to annualized adjusted funds flow	**0.8x**	1.4x	0.6x

Tamarack's net debt, including working capital deficiency but excluding the fair value of financial instruments, totaled $173.2 million as at December 31, 2017. This compares to the previous quarter and the fourth quarter of 2016, in which net debt of $194.9 million and $52.3 million was recorded, respectively. Tamarack's fourth quarter 2017 net debt to annualized adjusted funds flow improved to 0.8 times compared to 1.4 times as at the end of the third quarter 2017, due to increased production volumes and an improvement in forward strip commodity prices.

The $198.5 million invested during 2017 for capital expenditures and property acquisitions, net of dispositions, was funded approximately 80% by Tamarack's adjusted funds flow ($158.4 million) and approximately 20% ($40.1 million) by an increase in net debt.

With continued commodity price volatility impacting the oil and gas industry, Tamarack's strategy remains focused on preserving balance sheet strength by adjusting capital spending as appropriate to respond to changes in commodity prices. Tamarack intends to maintain balance sheet flexibility which allows the Company to be opportunistic and take advantage of potential opportunities within core areas. The Viking Acquisition that closed on January 11, 2017, and the tuck-in acquisitions completed during the third and fourth quarters of 2017 are consistent with this approach. 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 to optimize capital efficiencies. "Capital cost payout" or "payout" is a non-IFRS measure and 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.

Share Capital

At December 31, 2017, Tamarack had 228,510,381 common shares, 4,555,667 options and 5,818,382 RSUs outstanding. At March 5, 2018, there were 228,608,714 common shares, 5,818,382 options and 5,800,049 RSUs outstanding. This compares to December 31, 2016, at which time there were 137,527,475 common shares, 5,327,051 options and 3,063,167 RSUs outstanding. The Company had 228,066,207 and 225,306,148 weighted average basic common shares outstanding during the three months and year ended December 31, 2017. No preferred shares of Tamarack are issued and outstanding.

On January 11, 2017, the Company issued 90,142,906 common shares on closing of the Viking Acquisition.

On December 29, 2016, the Company issued 500,000 flow-through common shares, related to Canadian exploration expenditures, at $5.00 per share for total gross proceeds of $2.5 million. As of December 31, 2017, the Company had incurred the full $2.5 million of qualifying expenditures.

At December 31, 2017, and December 31, 2016, there were 1,155,007 preferred shares of Tamarack Acquisition Corp. ("TAC Preferred Shares") which are exchangeable into 1,110,584 common shares of the Company. The TAC Preferred Shares are fully vested at December 31, 2017 and are exchangeable into common shares of Tamarack at an exchange price of $3.12 per common share. An exchange of the TAC Preferred Shares is at the election of the Company under certain circumstances.

Bank Debt

The Company currently has a revolving credit facility in the amount of $270 million and a $20 million operating facility (collectively the "Facility") with a syndicate of lenders. The Facility totals $290 million, lasts for a 364 day period and will be subject to its next 364 day extension by May 25, 2018. If not extended on May 25, 2018, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date on May 25, 2019.

The interest rate on the Facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio as defined in the Facility. The interest rate will vary depending on the lending vehicle employed and the Company's current debt-to-cash-flow ratio. Interest on banker's acceptance ("BA") notes will vary from a low of the bank's posted BA rate plus 2.0% to a high of the bank's posted BA rate plus 3.5% while interest on prime lending varies from a low of the bank's prime rate plus 1.0% to a high of the bank's prime rate plus 2.5%. The standby fee for the Facility will vary as per a pricing grid from a low of 0.5% to a high of 0.875% on the undrawn portion of the Facility. The Facility has been secured by a $550 million supplemental debenture with a floating charge over all assets. As the available lending limits of the two facilities are based on the bank's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review.

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

Guidance

Tamarack's 2017 production of 20,136 boe/d was slightly above the upper end of its full year guidance range of 19,000 to 20,000 boe/d and weighted approximately 60% to oil and NGL. In response to the prevailing weakness in Canadian natural gas pricing during 2017, Tamarack made a conscious decision to allocate capital to drilling locations and other projects that have a higher oil and liquids weighting, which positively impacted its production profile and operating netbacks. Tamarack's original 2017 capital expenditure budget was set at $165 to $175 million, and during the fourth quarter, the Company announced its intention to accelerate an estimated $10 to 15 million from its planned Q1/18 program into 2017, increasing full year guidance (including tuck-in acquisitions) to $195-198 million. Ultimately, the Company accelerated $8 million, investing a total of $192.3 million, and drilled 133 gross (126.4 net) wells, including 104 (99.0 net) Viking wells, 16 (15.3 net) Cardium wells, five (5.0 net) heavy oil wells and three (3.0 net) Mannville wells, as well as five (4.1 net) wells in other areas.

Tamarack's year-end 2017 net debt totaled $173.2 million, which represents a net debt to fourth quarter 2017 annualized adjusted funds flow ratio of 0.8 times, lower than the Company's forecast ratio of 1.0 times. Tamarack's continued strong liquidity ensures the Company is well positioned to execute its 2018 capital program, designed to meet the objective of maintaining a strong and flexible balance sheet in the context of a volatile commodity price environment while delivering debt-adjusted per share growth in production and adjusted funds flow.

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

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

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

(2) Refer to definition of adjusted funds flow under "Non-IFRS Measures"

The Company will continue to closely monitor current and future commodity prices and has the ability to accelerate or reduce capital expenditures accordingly should commodity prices fluctuate from levels outlined in the assumptions above.

Commitments

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

($ thousands)	2018	2019	2020	2021	2022	2023	2024+
Bank debt	–	163,889	–	–	–	–	
Office lease	542	542	263	–	–	–	
Take or pay commitments(1)	986	–	–	–	–	–	
Rental fee(2)	5,741	5,741	5,741	5,741	3,870	1,999	1,142
Gas transportation(3)	2,448	730	229	76	–	–	
Total	9,717	170,902	6,233	5,817	3,870	1,999	1,142

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

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

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

Unit Cost Calculation

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

Abbreviations

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

Non–IFRS Measures

This document contains the terms "funds from operations", adjusted funds flow", "net debt", "netbacks" and "capital cost payout", which are non-IFRS financial measures. The Company uses these measures to help evaluate its performance. These non-IFRS financial measures do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures presented by other issuers. The Company uses funds from operations and adjusted funds flow as key measures to demonstrate the

Company’s ability to generate funds to repay debt and fund future capital investment. The Company uses net debt (bank debt plus working capital deficiency and excluding fair value of financial instruments) as an alternative measure of outstanding debt. The Company considers corporate netbacks a key measure as it demonstrates corporate profitability relative to current commodity prices. Netbacks, which have no IFRS equivalent, are calculated on a per boe basis by deducting royalties and production and transportation costs from petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts. The Company also considers capital cost payout a key measure as it demonstrates the financial status of the Company’s projects.

(a) **Funds from Operations and Adjusted Funds Flow -** Tamarack’s method of calculating funds from operations and adjusted funds flow may differ from other companies, and therefore may not be comparable to measures used by other companies. Tamarack calculates funds from operations as cash provided operating activities, as determined under IFRS, before the changes in non-cash working capital related to operating activities and before transaction costs related to acquisitions or dispositions that are not part of regular ongoing operations. Adjusted funds flow represents funds from operations before abandonment expenditures. The Company believes the uncertainty surrounding the timing of collection, payment or incurrence of these items makes them less useful in evaluating Tamarack’s operating performance. Tamarack uses funds from operations and adjusted funds flow as a key measure to demonstrate the Company’s ability to generate funds to repay debt and fund future capital investment.

A summary of this reconciliation is presented as follows:

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2017**	2016	**2017**	2016
Cash provided by operating activities	**$50,056**	$17,609	**$144,525**	$60,738
Transaction costs	**–**	–	**5,663**	596
Changes in non-cash working capital	**7,304**	2,811	**7,297**	2,612
Funds from operations	**$57,360**	$20,420	**$157,485**	$63,946
Abandonment expenditures	**223**	33	**898**	218
Adjusted funds flow	**$57,583**	$20,453	**$158,383**	$64,164

(b) **Operating Netback** - Management uses certain industry benchmarks, such as operating netback, to analyze financial and operating performance. This benchmark does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback equals total petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts, less royalties and production and transportation costs calculated on a per boe basis. Management considers operating netback an important measure to evaluate its operational performance, as it demonstrates field level profitability relative to current commodity prices. The calculation of the Company’s netbacks can be seen on page 7 in the section titled “Operating Netback”.

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

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

($ thousand)	December 31, 2017	December 31, 2016
Bank debt	$163,889	$45,227
Accounts payable and accrued liabilities	51,059	25,015
Accounts receivable	(38,673)	(16,557)
Prepaid expenses and deposits	(3,095)	(1,369)
Net debt	$173,180	$52,316

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

Selected Quarterly Information

Three months ended	**Dec. 31, 2017**	Sep. 30, 2017	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016
Sales volumes								
Natural gas *(mcf/d)*	**51,956**	49,987	47,696	45,852	31,226	29,007	27,462	25,818
Oil and NGL *(bbls/d)*	**14,148**	12,210	11,387	10,154	6,249	5,955	4,959	5,279
Average boe/d *(6:1)*	**22,807**	20,541	19,336	17,796	11,453	10,790	9,536	9,582
Product prices								
Natural gas *($/mcf)*	**1.89**	1.62	3.01	2.89	3.27	2.54	1.62	2.03
Oil and NGL *($/bbl)*	**62.34**	50.29	51.77	55.74	52.88	45.29	45.35	30.90
Oil equivalent *($/boe)*	**42.97**	33.83	37.91	39.25	37.76	31.82	28.25	22.50
(000s, except per share amounts)								
Financial results								
Gross revenues	**90,160**	63,927	66,715	62,870	39,793	31,588	24,517	19,619
Cash provided by operating activities	**50,056**	35,237	34,537	24,695	17,609	14,086	14,560	14,483
Adjusted funds flow(1)	**57,583**	34,774	33,670	32,356	20,453	17,172	15,364	11,175
Per share – basic	**0.25**	0.15	0.15	0.15	0.15	0.13	0.13	0.11
Per share – diluted	**0.25**	0.15	0.15	0.15	0.15	0.13	0.13	0.11
Net income (loss)	**(12,525)**	(6,742)	3,053	2,290	(8,425)	(3,196)	(10,368)	(5,835)
Per share – basic	**(0.05)**	(0.03)	0.01	0.02	(0.06)	(0.02)	(0.09)	(0.06)
Per share – diluted	**(0.05)**	(0.03)	0.01	0.02	(0.06)	(0.02)	(0.09)	(0.06)
Capital expenditures	**35,516**	74,063	19,002	63,721	14,863	14,497	10,309	17,149
Net acquisitions (dispositions)	**1,713**	2,962	1,301	75,995	(2,446)	85,308	–	–
Total assets	**1,207,809**	1,206,886	1,178,404	1,186,285	663,564	679,259	542,917	553,135
Net debt(1)	**173,180**	194,917	152,354	165,561	52,316	62,817	57,791	62,696
Bank debt	**163,889**	162,164	140,795	135,484	45,227	48,598	48,630	50,056
Decommissioning obligations	**177,793**	167,102	171,909	164,012	112,115	122,810	68,149	65,643

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

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

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

- The Company recorded impairment charges on its heavy oil, light oil and certain natural gas related CGUs due to falling oil and gas prices in the amount of $17.0 million in Q4 2017.

Selected Annual Information

	2017	2016	2015
Sales volumes			
Natural gas *(mcf/d)*	**48,893**	28,388	20,038
Oil and NGL *(bbls/d)*	**11,987**	5,613	3,703
Average boe/d *(6:1)*	**20,136**	10,344	8,448
Product prices			
Natural gas *($/mcf)*	**2.32**	2.41	2.85
Oil and NGL *($/bbl)*	**55.36**	44.06	45.76
Oil equivalent *($/boe)*	**38.60**	30.51	34.43
(000s, except per share amounts)			
Financial Results			
Gross revenues	**283,672**	115,517	106,146
Net loss	**(13,924)**	(27,823)	(17,329)
Per share – basic and diluted	**(0.06)**	(0.23)	(0.19)
Capital expenditures	**192,302**	56,819	62,200
Net acquisitions (dispositions)	**81,971**	82,862	45,231
Total assets	**1,207,809**	663,564	549,068
Net debt[1]	**173,180**	52,316	97,941
Bank debt	**163,889**	45,227	63,331

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

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

- The volatility in commodity prices and the resultant effect on revenue, cash provided by operating activities and earnings.
- The Company uses derivative contracts to reduce the financial impact of volatile commodity prices which can cause significant fluctuations in earnings due to unrealized gains and losses recognized on a quarterly basis.
- On January 11, 2017, Tamarack closed the Viking Acquisition which added assets in Southeast Alberta and Southwest Saskatchewan; in 2017 this acquisition added $62.3 million to oil and natural gas revenue and contributed $1.1 million to net loss.
- During the third quarter of 2016, Tamarack closed the strategic Penny and Redwater Acquisitions; in 2016 these acquisitions added $15.4 million to oil and natural gas revenue and contributed $0.1 million to the net loss.
- On June 15, 2015, the Company acquired certain working interests in developed petroleum and natural gas properties in the Alder Flats area of Alberta (the "Alder Flats Acquisition"); in 2015 this acquisition added $7.3 million to oil and natural gas revenue and contributed $1.0 million to net loss.
- The Company recorded $5.7 million in transaction costs in the first quarter of 2017 related to the Viking Acquisition and recorded $0.6 million in transaction costs in the third quarter of 2016

related to the Penny and Redwater Acquisitions. The Company also recorded $1.0 million in transaction costs in the second and third quarters of 2015 related to the Alder Flats Acquisition.

- The Company recorded impairment charges on its heavy oil, light oil and certain natural gas related CGUs due to falling oil and gas prices in the amount of $17.0 million in 2017, $0.7 million in 2016 and $26.1 million in 2015.

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** – Oil and natural gas reserves, as defined by the Canadian Securities Administrators in National Instrument 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.

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

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

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

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

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

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

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

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

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

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

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

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

Future Accounting Pronouncements

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

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

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

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

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.

The Company further improved the internal review process related to financial reporting and implemented increased segregation of duties policies as a result of an increase to the number of employees resulting from the significant growth experienced in 2017. These changes in the Company's DCP and its ICFR were made during the year ended December 31, 2017 to maintain the effectiveness of the Company's internal controls over financial reporting.

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

Business Risks

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

Financial Risks

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

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

Operational Risks

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

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

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

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

Regulatory Risks

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

Forward-Looking Statements

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

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

- the intentions of management and the Company;
- the availability, terms, use and renewal of credit facilities;
- estimated production rates in 2018;
- future production and transportation costs and G&A expenses;
- Tamarack's focus on preserving balance sheet strength by adjusting capital spending relative to commodity prices and reducing production costs on newly acquired assets;
- Tamarack's primary focus areas for production growth;
- tuck-in acquisitions in Tamarack's core areas;
- future drilling plans;
- Tamarack's strategy of focusing on drilling wells that a target a certain return on capital cost payout and Tamarack's ability to control cost or reduce capital, production and transportation costs to optimize capital efficiencies;

- deferred tax liabilities;
- expectations as to royalty rates as a percentage of revenue;
- future capital expenditures and capital program funding;
- estimated year end debt to adjusted funds flow (including hedges) ratio;
- the Company's capital program and guidance for 2018;
- derivative contracts and Tamarack's commodity price and foreign exchange rate risk management activities, including strategies to minimize exposure to Alberta gas market fluctuations;
- expectations as to oil and natural gas pricing in 2018 and beyond;
- expectations as to oil and natural gas weighting in 2018; and
- the ability of the Company to take advantage of opportunities that may arise in the low commodity price environment.

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

- future commodity prices and the actual prices received for the Company's products;
- expected production and transportation costs and G&A expenses;
- estimated reserves of oil and natural gas;
- the ability to obtain equipment and services in the field in a timely and efficient manner;
- the ability to add production and reserves through acquisition and/or drilling at competitive prices;
- the timing of anticipated future production additions from the Company's properties and acquisitions;
- the realization of anticipated benefits of acquisitions, including the Penny and Redwater Acquisitions, the Viking Acquisition and the tuck-in acquisition at Penny, and drilling programs in relation thereto;
- drilling results, including field production rates and decline rates;
- the continued application of horizontal drilling and fracturing techniques and pad drilling;
- the continued availability of capital and skilled personnel;
- the ability to obtain financing on acceptable terms;
- the accuracy of Tamarack's geological interpretation of its drilling and land opportunities, including the ability of seismic activity to enhance such interpretation;
- the impact of increasing competition;
- the ability of the Company to secure adequate product transportation;
- the ability to enter into future commodity derivative contracts on acceptable terms; and
- the continuation of the current tax, royalty and regulatory regime.

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

- the material uncertainties and risks described under the headings "Critical Accounting Estimates", "Future Accounting Pronouncements", "Disclosure Controls and Internal Controls

Over Financial Reporting”, “Business Risks”, “Financial Risks”, “Operational Risks” and “Regulatory Risks”;

- the material assumptions and observations described under the headings “Production”, “Petroleum and Natural Gas Sales”, "Royalties”, “Production and Transportation Expenses”, “Operating Netback”, “General and Administrative (“G&A”) Expenses”, “Stock-Based Compensation Expenses”, “Interest Expense”, “Depletion, Depreciation, Amortization and Accretion (“DDA&A”)”, “Income Taxes”, “Adjusted Funds Flow and Net Loss”, “Capital Expenditures (Including Exploration and Evaluation Expenditures)”, “Acquisitions”, “Impairment”, “Liquidity and Capital Resources”, “Guidance”, “Commitments” and “Selected Quarterly Information” and “Selected Annual Information”;
- the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- delays or changes in plans with respect to exploration or development projects or capital expenditures;
- volatility in market prices for oil and natural gas;
- uncertainties associated with estimating oil and natural gas reserves and the ability of the Company to realize value from its properties;
- geological, technical, drilling and processing problems;
- facility and pipeline capacity constraints and access to processing facilities and to market for production;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- marketing and transportation;
- prevailing weather and break-up conditions;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- 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, in particular low prices for all commodities produced by the Company, increased supply resulting from evolving exploitation methods, the attitude of lenders and investors towards corporations in the energy industry, potential changes to royalty and taxation regimes and to environmental and other government regulations, the condition of financial markets generally, as well as the stability of joint venture and other business partners, all of which are outside the control of the Company. Also to be considered are increased levels of political uncertainty and possible changes to existing international trading agreements and relationships. Legal challenges to asset ownership, limitations to rights of access and adequacy of pipelines or alternative methods of getting production to market may also have a significant effect on the Company’s business. Additional information on these and other factors that could affect the business, operations or financial results of Tamarack are included in reports on file with applicable securities regulatory authorities, including but not limited to Tamarack’s Annual Information Form for the year ended December 31, 2017, which may be accessed on Tamarack’s SEDAR profile at www.sedar.com or on the Company's website at www.tamarackvalley.ca.

The forward-looking statements 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 or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

The capital efficiency metric referenced in the corporate presentation of the Company, which can be found from time to time on the Company's website, has been withdrawn at the request of the securities regulatory authorities in Canada which take the view that such metric is a non-IFRS measure.