MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the three and nine months ended September 30, 2016 and 2015. This MD&A is dated and based on information available on November 7, 2016 and should be read in conjunction with the unaudited condensed consolidated interim financial statements and notes for the three and nine months ended September 30, 2016 and 2015. Additional information relating to Tamarack, including Tamarack's annual information form, is available on SEDAR at www.sedar.com and Tamarack's website at www.tamarackvalley.ca.

The condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The Company uses certain non-IFRS and additional IFRS measures in this MD&A. For a discussion of those measures, including the method of calculation, please refer to section entitled "Non-IFRS and Additional IFRS Measures" on pages 15 and 16. Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

About Tamarack

Tamarack is an oil and gas exploration and production company committed to long-term growth and the identification, evaluation and operation of resource plays in the Western Canadian Sedimentary Basin. Tamarack's strategic direction is focused on two key principles – targeting repeatable and relatively predictable plays that provide long-life reserves, and using a rigorous, proven modeling process to carefully manage risk and identify opportunities. The Company has an extensive inventory of low-risk, oil development drilling locations focused primarily in the Cardium and Viking fairways in Alberta that are economic at a variety of oil and natural gas prices. With this type of portfolio and an experienced and committed management team, Tamarack intends to continue delivering on its strategy to maximize shareholder return while managing its balance sheet.

Strategic Acquisitions Completed During the Quarter

During the quarter, Tamarack closed two strategic acquisitions, including certain assets in the Penny area of Southern Alberta and the consolidation of assets in the Redwater and Wilson Creek areas of Alberta (the "Penny and Redwater Acquisitions") on July 12, 2016 and July 25, 2016, respectively. The assets in Penny are comprised of a light oil pool under waterflood with low recoveries and low decline rates plus strategic infrastructure, while the Redwater and Wilson Creek assets included 95 (60 net) sections of land and significant strategic infrastructure. The combined total purchase price for the Penny and Redwater Acquisitions was approximately $86 million, and as of the closing date included approximately 1,900 boe/d of predominantly light oil and natural gas liquids production. The Company closed a bought deal financing on July 12, 2016 raising gross proceeds of $81.6 million which provided the primary funding for the Penny and Redwater Acquisitions.

Transformative Business Combination Adds Additional Viking Oil Assets

On November 2, 2016, Tamarack announced an arrangement agreement (the "Arrangement Agreement") providing for the acquisition by Tamarack of all the issued and outstanding common shares of Spur Resources Ltd., which will hold Spur's Viking oil assets at closing (the "Combination"). This transaction will build upon the Company's existing Viking asset base at Redwater and core Cardium assets at Wilson Creek. Under the terms of the Arrangement Agreement, Tamarack will issue an aggregate of 90.1 million common shares of Tamarack (subject to rounding) and a fixed portion of $57.3 million in cash. The Company will also be assuming Spur's net debt, estimated to be $25.7 million as at November 30, 2016, after accounting for proceeds from the exercise of all outstanding options of Spur, plus severance and transaction costs. Based upon the previous 10-day VWAP of Tamarack of $3.60 per share, the total consideration payable by Tamarack, including the assumption of debt, will be approximately $407.5 million.

Pro forma the Combination, Tamarack will be repositioned as an intermediate oil-weighted Cardium and Viking focused growth company with production of approximately 17,250 boe/d (54% light oil and NGLs) and over 680 net total identified locations that pay out in 1.5 years or less at current strip prices. The Company expects to maintain financial strength and flexibility with pro forma net debt to 2017E cash flow at current strip prices of 0.9 times, and no requirement for an equity financing to fund development of the combined assets.

Closing of the Combination is expected to occur on or about January 11, 2017 and is subject to the receipt by Tamarack and Spur of all court, stock exchange and other regulatory approvals, receipt of the requisite shareholder approvals of Tamarack and Spur, no material adverse change having occurred in Spur and a number of other matters customary in transactions of this nature. All directors and officers of Spur, representing approximately 34% of the issued and outstanding Spur Shares, have entered into support agreements with Tamarack pursuant to which they have agreed to vote their Spur Shares in favor of the Combination.

The Arrangement Agreement provides for a mutual break fee of $16,300,000 in the event of termination of the Arrangement Agreement in certain circumstances and a mutual third party expense reimbursement fee in the event that Tamarack or Spur shareholders do not approve the issuance of Tamarack Shares or the Combination, respectively, in certain circumstances. The Arrangement Agreement also provides for customary non-solicitation covenants, and exercise of fiduciary duty and right to match provisions, among other matters.

Under Tamarack's initial 2017 growth plans, the Company anticipates that it will allocate drilling capital approximately equally between the Spur Assets and existing Tamarack assets. An estimated 100 to 110 Viking oil wells are expected to be drilled on the Spur Assets, with approximately 80% in the Consort and Veteran areas, where acquired operated infrastructure can contribute to greater cost control and enhanced returns. On the Company's existing assets, Tamarack plans to drill between 15 and 17 net wells at Wilson Creek and Alder Flats, up to four net wells at Penny, and between 10 and 15 net wells at Redwater.

Tamarack's preliminary 2017 capital program and associated guidance ranges are designed to meet the objective of maintaining a strong and flexible balance sheet in the context of a volatile commodity price environment. The Company anticipates its 2017 capital expenditure budget to be between $160 and $170 million, with only $45 million expected to be spent during the first five months of 2017. The preliminary 2017 capital program is based on the following 2017 commodity prices assumptions: WTI $50/bbl USD, Edmonton Par price $61.33/bbl, AECO $2.75/GJ and a Canadian/US dollar exchange rate range of $0.75. Annual production guidance is expected to be between 19,000 and 20,000 boe/d, with a target 2017 exit rate between 20,000 and 21,000 boe/d.

Production

	Three months ended September 30,			Nine months ended September 30,		
	2016	2015	% change	**2016**	2015	% change
Production						
Light oil (bbls/d)	**4,534**	3,499	30	**3,999**	3,517	14
Heavy oil (bbls/d)	**343**	660	(48)	**379**	595	(36)
Natural gas liquids (bbls/d)	**1,078**	890	21	**1,021**	663	54
Natural gas (mcf/d)	**29,007**	22,005	32	**27,435**	18,962	45
Total (boe/d)	**10,790**	8,717	24	**9,972**	7,935	26
Percentage of oil and natural gas liquids	**55%**	58%		**54%**	60%	

Tamarack achieved strong production results for the first nine months of 2016, averaging 9,972 boe/d for the period. Better than expected capital efficiencies and higher than expected production results from wells drilled during 2016 contributed to volumes that nearly exceeded annual average production guidance of 9,700 to 10,000 boe/d, despite experiencing over 400 boe/d of unexpected production curtailments in the second quarter. The Company expects to average 9,800 to 10,500 boe/d for the second half of 2016 and exit 2016 at approximately 11,000 boe/d due to production additions associated with the Penny and Redwater Acquisitions and a modest second half drilling program. See page 14 for a more comprehensive summary of the Company's reaffirmed 2016 guidance.

Average production for the third quarter of 2016 increased by 13% to 10,790 boe/d from 9,536 boe/d in the second quarter of 2016. Third quarter volumes were positively impacted by a combined 2,046 boe/d attributable to the Penny and Redwater Acquisitions, and volume additions from three (2.9 net) Cardium oil wells and one (1.0 net) heavy oil well that were brought on stream during the third quarter. By the end of the quarter, production from the recently acquired Penny and Redwater assets exceeded expectations by approximately 480 boe/d due to successful workovers and shallower decline rates.

Crude oil and natural gas liquids production in the third quarter of 2016 averaged 5,955 bbls/d, an increase of 20% compared to the second quarter 2016 production of 4,959 bbls/d. A combined 1,541 bbls/d were added due to the Penny and Redwater Acquisitions plus the impact of three (2.9 net) Cardium oil wells and one (1.0 net) heavy oil well that were brought on stream in the third quarter.

Tamarack's oil and natural gas liquids represented 55% of total production in the third quarter of 2016 compared to 52% for the second quarter of 2016. For 2016, the Company expects its oil and natural gas liquids weighting to fluctuate between 50% and 60% depending on the timing of production additions from its higher liquids-weighted areas of Wilson Creek, Redwater and Penny, compared to additions coming from the higher natural gas-weighted areas of Alder Flats and Brazeau. Oil and natural gas weightings may also be affected by production additions associated with future drilling of liquids-rich Mannville gas wells in the Wilson Creek area.

Natural gas production averaged 29,007 mcf/d in the third quarter of 2016, an increase of 6% over the 27,462 mcf/d produced in the prior quarter. The increase was primarily due to the Penny and Redwater Acquisitions which added a combined 2,995 mcf/d to the period's production average.

Compared to the prior year, third quarter 2016 production of 10,790 boe/d was 24% higher than 8,717 boe/d in the same period in 2015. This increase is attributable to the successful 2016 drilling program which positively impacted third quarter 2016 volumes, as well as the impact of almost a full quarter of production from assets acquired in the Penny and Redwater Acquisitions, partially offset by expected declines from existing production.

Average production for the nine months ended September 30, 2016 was 9,972 boe/d, 26% higher than the 7,935 boe/d produced during the same period in 2015. The increase is attributable to the successful 2016 drilling program, as well as the impact of a full period of production from certain working interests acquired in developed petroleum and natural gas properties in the Alder Flats area of Alberta (the "Wilson Creek / Alder Flats Acquisition") and the impact of nearly a full quarter of production from assets acquired in the Penny and Redwater Acquisitions, partially offset by expected declines from existing production.

Petroleum, Natural Gas Sales and Royalties

	Three months ended September 30,			Nine months ended September 30,		
	2016	2015	% change	**2016**	2015	% change
Revenue						
Oil and NGLs	**$24,809,977**	$21,625,992	15	**$60,113,748**	$63,267,241	(5)
Natural gas	**6,778,110**	6,153,327	10	**15,609,986**	15,153,254	3
Total	**$31,588,087**	$27,779,319	14	**$75,723,734**	$78,420,495	(3)
Average realized price						
Light oil ($/bbl)	**51.83**	54.39	(5)	**47.19**	54.06	(13)
Heavy oil ($/bbl)	**39.29**	49.15	(20)	**32.89**	47.31	(30)
Natural gas liquids ($/bbl)	**19.68**	13.78	43	**17.83**	20.28	(12)
Combined average oil and NGLs ($/boe)	**45.29**	46.56	(3)	**40.64**	48.53	(16)
Natural gas ($/mcf)	**2.54**	3.04	(16)	**2.08**	2.93	(29)
Revenue $/boe	**31.82**	34.64	(8)	**27.72**	36.20	(23)
Benchmark pricing:						
Edmonton Par (Cdn$/bbl)	**54.33**	54.66	(1)	**48.74**	58.65	(17)
Hardisty Heavy (Cdn$/bbl)	**40.14**	44.32	(9)	**35.68**	48.13	(26)
AECO daily index (Cdn$/mcf)	**2.31**	2.89	(20)	**1.84**	2.76	(33)
AECO monthly index (Cdn$/mcf)	**2.19**	2.77	(21)	**1.84**	2.79	(34)
Royalty expenses	**$2,219,838**	$3,051,720	(27)	**$5,049,197**	$8,000,773	(37)
$/boe	**2.24**	3.81	(41)	**1.85**	3.69	(50)
percent of sales	**7**	11	(36)	**7**	10	(30)

Revenue from crude oil, natural gas and associated natural gas liquids sales was $31,588,087 in the third quarter of 2016, which was 29% higher than the $24,516,988 generated in the second quarter of 2016 and 14% higher than the $27,779,319 generated in the third quarter of 2015. The 29% increase in third quarter 2016 revenue over the previous quarter is attributable to natural gas prices that were 56% higher, a 20% increase in crude oil and natural gas liquids production and a 6% increase in natural gas production. Revenue in the third quarter 2016 increased 14% relative to the same period in 2015 primarily due to a 24% increase in production volumes, partially offset by crude oil and natural gas liquids prices that were 3% lower and 16% lower natural gas prices. Revenue in the first nine months of 2016 declined 3% compared to the first nine months of 2015 despite a 26% increase in production volumes, primarily due to a 16% decrease in crude oil and natural gas liquids pricing and a 29% decrease in natural gas prices.

Tamarack's realized prices for natural gas and the combined oil and natural gas liquids averaged $2.54/mcf and $45.29/bbl in the third quarter of 2016, respectively, compared to $1.62/mcf and $45.35/bbl in the second quarter of 2016 and $3.04/mcf and $46.56/bbl in the third quarter of 2015.

The realized crude oil prices for the three and nine months ended September 30, 2016 and 2015 generally correlate to the posted Edmonton Par price for those periods. Natural gas liquids are priced at varying discounts to the posted Edmonton Par price depending on market conditions, pipeline capacity and seasonality. Natural gas liquids prices decreased by a greater margin than the Edmonton Par price due to high North American supply and inventory combined with warmer winter conditions which led to lower than normal propane demand. The Company expects the high supply and inventory trend to remain consistent for the balance of 2016.

The Company's realized heavy oil price for the three and nine months ended September 30, 2016 and 2015 generally correlate to the Hardisty Heavy price for those periods.

For the three and nine months ended September 30, 2016, Tamarack's realized natural gas prices generally correlate to AECO daily index pricing, however variances can arise during periods of rapid price increases or decreases, because the portion of the Company's sales that are based mainly on the daily index will not correlate to the monthly index.

At September 30, 2016, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	2,000 bbls/day	October 1, 2016 – December 31, 2016	WTI fixed price	Cdn $66.43
Crude oil	2,200 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $60.54
Crude oil	2,200 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $61.60
Crude oil	1,000 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $64.35
Crude oil	200 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $67.45
Natural gas	3,000 GJ/day	October 1, 2016 – October 31, 2016	AECO fixed price	Cdn $2.53
Natural gas	9,000 GJ/day	October 1, 2016 – December 31, 2016	AECO fixed price	Cdn $2.31
Natural gas	12,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.68
Natural gas	12,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.37
Natural gas	12,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.41
Natural gas	9,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $2.79

For the nine months ended September 30, 2016, the commodity contracts were fair valued in a liability position of $3,047,721 (December 31, 2015 - $12,468,101 asset) recorded on the balance sheet resulting in an unrealized loss of $15,515,822 recorded in earnings.

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

At September 30, 2016, the Company held physical commodity contracts as follows.

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Natural gas	2,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.55

Since September 30, 2016, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	200 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $68.55
Crude oil	200 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $70.00
Natural gas	2,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $3.20
Natural gas	4,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.81
Natural gas	2,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.78

Royalty expenses for the third quarter of 2016 were $2.24/boe or $2,219,838, representing 7% of revenue, compared to $1.21/boe or $1,048,997 for the second quarter of 2016, representing 4% of revenue. The $1.03/boe increase in royalties in the third quarter of 2016 compared to the second quarter of 2016 was related to the Company's annual gas cost allowance adjustment during the second quarter of 2016.

Royalties as a percentage of revenue were lower in the third quarter of 2016 compared to the third quarter of 2015, when royalty expenses were $3.81/boe or $3,051,720, representing 11% of revenue. The year over year decrease is due to the sliding scale mechanism which results in lower royalties when commodity prices are low, lower initial royalty rates on wells that were drilled between late 2015 and the first nine months of 2016, and the Company's annual gas cost allowance adjustment. These positive impacts were partially offset by higher royalty rates from wells acquired in the Wilson Creek / Alder Flats Acquisition in June 2015 and the Penny and Redwater Acquisitions in July 2016.

The royalty expense for the first nine months of 2016 was $1.85/boe or $5,049,197, representing 7% of revenue, compared to $3.69/boe or $8,000,773, representing 10% of revenue for the same period in 2015. The decrease in royalties as a percentage of revenue for the first nine months of 2016 relative to 2015 is due to the sliding scale mechanism which results in lower royalties when commodity prices are low, lower initial royalty rates on wells that were drilled between late 2015 and the first nine months of 2016, and the Company's annual gas cost allowance adjustment. These positive impacts were partially offset by higher royalty rates from wells acquired in the Wilson Creek / Alder Flats Acquisition in June 2015 and the Penny and Redwater Acquisitions in July 2016.

The Company expects royalty rates to increase in the fourth quarter of 2016 compared to the first nine months of 2016 due to a full quarter impact of the higher royalty rates associated with assets from the Penny and Redwater Acquisitions.

On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "MRF"). The MRF will take effect on January 1, 2017. Wells drilled prior to January 1, 2017 will continue to be governed by the current "Alberta Royalty Framework" for a period of 10 years until January 1, 2027. All wells drilled after January 1, 2017 will pay 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 MRF is not expected to materially impact netbacks on Tamarack's existing assets nor is it expected to materially impact the economics of future drilling.

Production Expenses

	Three months ended September 30,			Nine months ended September 30,		
	2016	2015	% change	**2016**	2015	% change
Total production expenses	**$11,493,859**	$11,264,333	2	**$31,241,159**	$28,313,619	10
Total ($/boe)	**$11.58**	$14.05	(18)	**$11.43**	$13.07	(13)

Production expenses for the third quarter of 2016 increased by 5% to $11.58/boe compared to $11.05/boe incurred during the second quarter of 2016. The Company expected operating costs on a per boe basis to increase as a result of the Penny and Redwater Acquisitions which feature higher per unit operating costs than Tamarack realizes in its other areas. During the next quarter, the Company expects to reduce operating costs on these recently acquired assets and anticipates operating costs to return to the $11.00/boe range. On an absolute basis, overall costs increased in the third quarter of 2016 to $11,493,859 compared to $9,592,542 in the second quarter of 2016. The increase in total production costs resulted from a 13% increase in production and the increase in per unit costs. The Company will focus efforts on reducing operating costs on the newly acquired assets during the remainder of 2016 to improve overall netbacks.

On a per unit basis, third quarter 2016 production expenses were 18% lower than the $14.05/boe realized in the same quarter of 2015, but increased 2% on an absolute basis to $11,493,859, compared to $11,264,333 for the same period in 2015. The lower per boe expenses in 2016 resulted from cost reductions at the Wilson Creek / Alder Flats and Heavy oil properties and from the impact of higher volumes across fixed costs which resulted in lower per unit costs. On an absolute basis, production expenses increased as a result of a 24% increase in production volumes and the impact of facility rental arrangements, partially offset by lower per unit costs.

Production expenses in the first nine months of 2016 were 13% lower at $11.43/boe compared to $13.07/boe during the same period in 2015, but increased 10% on an absolute basis to $31,241,159, compared to $28,313,619 for the same period in 2015. The lower per boe production expenses in 2016 resulted from cost reductions at the Wilson Creek / Alder Flats and Heavy oil properties and from the impact of higher volumes across fixed costs resulting in lower per unit costs. On an absolute basis, overall costs increased as a result of a 26% increase in production volumes and the impact of facility rental arrangements, partially offset by lower per unit costs.

Operating Netback

	Three months ended September 30,			Nine months ended September 30,		
($/boe)	**2016**	2015	% change	**2016**	2015	% change
Average realized sales	**31.82**	34.64	(8)	**27.72**	36.20	(23)
Royalty expenses	**(2.24)**	(3.81)	(41)	**(1.85)**	(3.69)	(50)
Production expenses	**(11.58)**	(14.05)	(18)	**(11.43)**	(13.07)	(13)
Operating field netback	**18.00**	16.78	7	**14.44**	19.44	(26)
Realized commodity hedging gain (loss)	**2.10**	5.35	(61)	**4.56**	4.61	(1)
Operating netback	**20.10**	22.13	(9)	**19.00**	24.05	(21)

Operating netback for the third quarter of 2016 decreased by 3% to $20.10/boe compared to $20.68/boe during the second quarter of 2016. This is attributable to a 5% increase in operating expense per boe

($11.58/boe versus $11.05/boe), a realized hedging gain of $2.10/boe in the third quarter of 2016 compared to $4.69/boe in the second quarter of 2016 and an 85% increase in royalty expense per boe ($2.24/boe versus $1.21/boe), partially offset by a 56% increase in natural gas prices ($2.54/mcf versus $1.62/mcf).

Third quarter 2016 operating netbacks decreased by 9% compared to $22.13/boe in the third quarter of 2015. This was due to a 3% decrease in oil and natural gas liquids prices ($45.29/bbl versus $46.56/bbl), a 16% decrease in natural gas prices ($2.54/mcf versus $3.04/mcf) and lower realized hedging gains ($2.10/boe versus $5.35/boe), partially offset by royalty expenses per boe that were 41% lower ($2.24/boe versus $3.81/boe) and operating expenses that were 18% lower ($11.58/boe versus $14.05/boe).

In the first nine months of 2016, operating netbacks decreased by 21% to $19.00/boe as compared to $24.05/boe realized for the same period in 2015. This was due to a 16% decrease in oil and natural gas liquids prices ($40.64/bbl versus $48.53/bbl) and a 29% decrease in natural gas prices ($2.08/mcf versus $2.93/mcf), partially offset by royalty expenses per boe that were 50% lower ($1.85/boe versus $3.69/boe) and operating expenses that were 13% lower ($11.43/boe versus $13.07/boe).

General and Administrative Expenses

	Three months ended September 30,			Nine months ended September 30,		
	2016	2015	% change	**2016**	2015	% change
Gross costs	**$2,372,087**	$2,309,655	3	**$6,969,291**	$6,973,411	(0)
Capitalized costs and recoveries	**(499,885)**	(576,232)	(13)	**(1,563,997)**	(1,514,611)	3
General and administrative costs	**$1,872,202**	$1,733,423	8	**$5,405,294**	$5,458,800	(1)
Total ($/boe)	**$1.89**	$2.16	(13)	**$1.98**	$2.52	(21)

General and administrative ("G&A") expenses for the third quarter of 2016 were $1.89/boe on costs of $1,872,202 compared to $2.03/boe on costs of $1,762,406 in the second quarter of 2016. Third quarter 2016 G&A costs per boe were 7% lower than the previous quarter due primarily to the impact of a 13% increase in production. During the third quarter of 2015, G&A expenses were $2.16/boe on costs of $1,733,423, while third quarter 2016 per boe G&A costs were 13% lower due to the impact of a 24% increase in production, partially offset by an 8% increase in absolute G&A costs.

For the first nine months of 2016, G&A expenses were $1.98/boe on costs of $5,405,294 compared to $2.52/boe on costs of $5,458,800 during the same period in 2015. The 21% decrease in G&A costs per boe for the first nine months of 2016 was due to the impact of a 26% increase in production.

Stock-based Compensation Expenses

Stock-based compensation expenses were $826,863 and $2,688,815 relating to stock options and restricted share awards for the three and nine months ended September 30, 2016, respectively, compared to $699,933 and $2,297,279 for the same periods in 2015. Stock-based compensation expenses are calculated based on graded vesting periods that are front-end loaded.

The Company capitalized $347,771 and $1,144,467 of stock-based compensation expenses related to exploration and development activities for the three and nine months ended September 30, 2016, compared to capitalizing $338,013 and $1,132,209 for the same periods in 2015.

Interest

Interest expense was $912,957 and $2,776,494 for the three and nine months ended September 30, 2016, respectively, compared to $1,387,002 and $4,043,972 for the same periods in 2015. The Company had

$48,597,685 drawn on its revolving credit facility at September 30, 2016, compared to $94,423,028 drawn on its bank line at September 30, 2015. Interest expense was lower for the three and nine months ended September 30, 2016 compared to the same periods in 2015 due to a lower average quarter over quarter amount drawn on the revolving credit facility. The average amount drawn for the three and nine months ended September 30, 2016 was approximately $50 million and $58 million, respectively, compared to an average amount drawn of approximately $91 million and $101 million during the same periods in 2015.

Depletion, Depreciation, Amortization and Accretion

The Company depletes its property, plant, and equipment 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 depletion, depreciation, and amortization expense.

	Three months ended September 30,			Nine months ended September 30,		
	2016	2015	% change	**2016**	2015	% change
Depletion and depreciation	**$16,904,646**	$13,901,611	22	**$46,978,924**	$43,165,433	9
Amortization of undeveloped leases	**202,981**	172,483	18	**557,018**	568,000	(2)
Accretion	**496,239**	267,592	85	**1,169,234**	708,614	65
Total	**$17,603,866**	$14,341,686	23	**$48,705,176**	$44,442,047	10
Depletion and depreciation ($/boe)	**$17.03**	$17.34	(2)	**$17.19**	$19.93	(14)
Amortization ($/boe)	**0.20**	0.22	(9)	**0.20**	0.26	(23)
Accretion ($/boe)	**0.50**	0.33	52	**0.43**	0.33	30
Total ($/boe)	**$17.73**	$17.89	(1)	**$17.82**	$20.52	(13)

Depletion, depreciation, amortization, and accretion (“DDA&A”) expense on a per boe basis for the third quarter of 2016 was $17.73/boe, compared to $17.80/boe during the second quarter of 2016. For the third quarter of 2016, DDA&A expense was $17,603,866 compared to $15,438,296 for the second quarter of 2016 due to a 13% increase in production.

Third quarter 2016 DDA&A expense of $17.73/boe remained relatively consistent compared to $17.89/boe for the same period in 2015. On an absolute basis, DDA&A expense of $17,603,866 was 23% higher in the third quarter of 2016 compared to $14,341,686 in the third quarter of 2015 due to a 24% increase in production.

For the first nine months of 2016 DDA&A expense was $17.82/boe, compared to $20.52/boe for the same period in 2015. The decrease is attributable to increased production related to lower-cost Cardium and heavy oil properties, and impairments to property, plant and equipment taken in the third quarter of 2015. On an absolute basis, DDA&A expense was 10% higher in the first nine months of 2016 at $48,705,176, compared to $44,442,047 during the same period in 2015, caused by a 26% increase in production and partially offset by lower per unit DDA&A.

Income Taxes

The Company did not incur any cash tax expense in the three and nine months ended September 30, 2016, nor does it expect to pay any cash taxes in 2016 or 2017 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three and nine months ended September 30, 2016, a deferred income tax expense of $907,707 and an income tax recovery of $4,396,825 was recognized, compared to a deferred income tax recovery of $2,929,781 and $8,065,362 for the same periods in 2015. There was a deferred tax recovery during the nine months ended September 30, 2016 and the three and nine months ended September 30, 2015 due to the pre-tax losses recognized in these periods. For the three months ended September 30, 2016 the impact of flow-through shares resulted in a deferred tax expense.

Funds from Operations and Net Income

	Three months ended September 30,			Nine months ended September 30,		
	2016	2015	% change	**2016**	2015	% change
Petroleum and natural gas sales	**$31,588,087**	$27,779,319	14	**$75,723,734**	$78,420,495	(3)
Royalties	**(2,219,838)**	(3,051,720)	27	**(5,049,197)**	(8,000,773)	37
Realized gain on financial instruments	**2,082,980**	4,288,134	(51)	**12,458,959**	9,987,577	25
Production expenses	**(11,493,859)**	(11,264,333)	(2)	**(31,241,159)**	(28,313,619)	(10)
General and administration expenses	**(1,872,202)**	(1,733,423)	(8)	**(5,405,294)**	(5,458,800)	1
Transaction costs	**(500,000)**	(12,791)	(3,809)	**(596,254)**	(1,044,308)	43
Interest	**(912,957)**	(1,387,002)	34	**(2,776,494)**	(4,043,972)	31
Funds from operations	**$16,672,211**	$14,618,184	14	**$43,114,295**	$41,546,600	4

Funds from operations during the third quarter of 2016 were $16,672,211 ($0.12 per share basic and diluted) compared to $15,363,924 ($0.13 per share basic and diluted) for the second quarter of 2016. The increase in the absolute amount is primarily the result of a 56% increase in natural gas prices and a 13% increase in production, partially offset by a 20% increase in production expenses, a 112% increase in royalty expense, $500,000 in transaction costs associated with the Penny and Redwater Acquisitions and a lower realized hedging gain.

Compared to funds from operations of $14,618,184 ($0.15 per share basic and diluted) in the same period in 2015, third quarter 2016 funds from operations were 10% higher as a result of a 24% increase in production and a 27% decrease in royalty expense, partially offset by a lower realized hedging gain, a 16% decrease in natural gas pricing and $500,000 in transaction costs related to the Penny and Redwater Acquisitions.

Funds from operations during the first nine months of 2016 were $43,114,295 ($0.37 per share basic and diluted) compared to $41,546,600 ($0.47 per share basic and diluted) for the same period in 2015. The increase in funds from operations on an absolute basis is primarily the result of a 26% increase in production, a higher realized hedging gain in 2016 and a 37% decrease in royalty expense, partially offset by a 29% decrease in natural gas pricing, a 16% decrease in crude oil and natural gas liquids pricing and a 10% increase in production expenses.

	Three months ended September 30,			Nine months ended September 30,		
($/boe)	**2016**	2015	% change	**2016**	2015	% change
Petroleum and natural gas sales	**$31.82**	$34.64	(8)	**$27.72**	$36.20	(23)
Royalties	**(2.24)**	(3.81)	41	**(1.85)**	(3.69)	50
Realized gain on financial instruments	**2.10**	5.35	(61)	**4.56**	4.61	(1)
Production expenses	**(11.58)**	(14.05)	18	**(11.43)**	(13.07)	13
General and administration expenses	**(1.89)**	(2.16)	13	**(1.98)**	(2.52)	21
Transaction costs	**(0.50)**	(0.02)	(2,400)	**(0.22)**	(0.48)	54
Interest	**(0.92)**	(1.73)	47	**(1.02)**	(1.87)	45
Funds from operations	**$16.79**	$18.22	(8)	**$15.78**	$19.18	(18)

Third quarter 2016 funds from operations decreased 5% to $16.79/boe from $17.71/boe in the second quarter of 2016 due to a 5% increase in production expenses per boe, an 85% increase in royalty expense per boe and a 55% decrease in the realized hedging gain, partially offset by a 56% increase in natural gas prices.

Compared to funds from operations of $18.22/boe realized in the third quarter of 2015, funds from operations in the third quarter of 2016 were 11% lower due to a 3% decrease in crude oil and natural gas liquids prices, a 16% decrease in natural gas prices and a 61% decrease in the realized hedging gain, partially offset by an 18% decrease in production expenses per boe, a 13% decrease in G&A expense per boe and a 41% decrease in royalty expense per boe.

For the first nine months of 2016, funds from operations decreased 18% to $15.78/boe compared to $19.18/boe realized in the same period of 2015 due to a 16% decrease in crude oil and natural gas liquids prices and a 29% decrease in natural gas prices, partially offset by a 13% decrease in production expenses per boe, a 21% decrease in G&A expense per boe and a 50% decrease in royalty expense per boe.

The Company recorded a net loss of $3,194,857 ($0.02 per share basic and diluted) during the three months ended September 30, 2016, compared to a net loss of $10,369,299 ($0.09 per share basic and diluted) for the previous quarter due primarily to the $528,632 unrealized loss on financial instruments in the third quarter of 2016 compared to an unrealized loss of $12,883,066 in the second quarter of 2016. Other factors contributing to a lower net loss for the third quarter of 2016 compared to the previous quarter include higher oil and natural gas revenue, which was partially offset by higher production expenses, higher depletion, depreciation and amortization expense and $500,000 in transaction costs related to the Penny and Redwater Acquisitions.

The Company had a net loss of $3,194,857 ($0.02 per share basic and diluted) during the three months ended September 30, 2016, compared to a net loss of $15,063,870 ($0.15 per share basic and diluted) for the same period in 2015. The factors causing a higher net loss in the third quarter of 2015 compared to the same period in 2016 were an impairment to property, plant and equipment taken in the third quarter of 2015, partially offset by an unrealized hedging gain, while the third quarter 2016 net loss was impacted by an unrealized hedging loss and higher depletion, depreciation and amortization expense.

The Company had a net loss of $19,398,693 ($0.17 per share basic and diluted) during the nine months ended September 30, 2016, compared to a net loss of $22,447,287 ($0.26 per share basic and diluted) for the same period in 2015. This was the result of an impairment to property, plant and equipment taken in 2015, partially offset by an unrealized hedging loss in 2016 compared to an unrealized hedging gain in the same period in 2015 and higher depletion, depreciation and amortization expense due to a 26% increase in production.

Capital Expenditures (including exploration and evaluation expenditures)

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

	Three months ended September 30,			Nine months ended September 30,		
	2016	2015	% change	**2016**	2015	% change
Land	**310,680**	$1,172	26,409	**1,488,812**	$412,716	261
Geological and geophysical	**23,984**	45,486	(47)	**436,857**	52,995	724
Drilling and completion	**13,290,166**	15,253,544	(13)	**34,110,171**	28,068,238	22
Equipment and facilities	**591,625**	6,548,911	(91)	**4,857,771**	14,059,263	(65)
Capitalized G&A	**181,115**	228,275	(21)	**707,324**	712,687	(1)
Office equipment	**99,818**	150,336	(34)	**355,300**	151,821	134
Total capital expenditures	**$14,497,388**	$22,227,724	(35)	**$41,956,235**	$43,457,720	(3)
Property acquisitions	**86,404,035**	1,230,258	6,923	**86,404,035**	55,403,908	56
Proceeds from disposal of property, plant and equipment	**–**	(292,354)	(100)	**–**	(2,247,937)	(100)
Total net capital expenditures	**$100,901,423**	$23,165,628	336	**$128,360,270**	$96,613,691	33

During the third quarter of 2016, the Company drilled, completed and equipped 4 (3.9 net) Cardium oil wells and drilled 2 (2.0 net) Viking oil wells.

2016 Drilling Summary (including wells spudded by September 30, 2016)		
	Gross	Net
Heavy Oil	2.0	2.0
Viking	2.0	2.0
Mannville	1.0	0.8
Cardium	9.0	8.4
	14.0	13.2

The Company has also been focused on adding drilling inventory through tuck-in land acquisitions and through acquiring land in its core areas at land sales. During the third quarter, one minor deal was completed, which added 1 net section of undeveloped land, as well as 4.5 net sections of undeveloped land through a successful land sale.

The Company's net undeveloped land totaled 246,256 acres at the end of the third quarter of 2016.

Liquidity and Capital Resources

Tamarack's net debt, including working capital deficiency but excluding the fair value of financial instruments, was $62,817,409 at September 30, 2016. Tamarack's net debt at September 30, 2015 was $105,837,205 and at December 31, 2015 was $97,940,880. During the nine months ended September 30, 2016 the Company reduced net debt by $35,123,471 through an equity issuance described below, which improved financial flexibility. Tamarack's September 30, 2016 net debt to annualized funds from operations was 1.0 times as compared to year end December 31, 2015 of 1.3 times.

On July 12, 2016 the Company completed a bought deal financing in concert with the Penny and Redwater Acquisitions, resulting in the issuance of 20,110,050 common shares at $3.66 per share for total gross proceeds of $73,602,783. This included an over-allotment option being exercised for 2,623,050 common shares. Certain officers, directors and employees acquired 99,950 common shares for gross proceeds of $365,817.

On July 12, 2016 the Company also issued 1,952,000 flow-through common shares related to Canadian development expenditures at $4.10 per share for total gross proceeds of $8,003,200. Certain officers and directors acquired 4,900 flow-through common shares for gross proceeds of $20,090.

On March 18, 2016, the Company completed a bought deal financing and issued 14,966,100 Common Shares at $2.92 per share for total gross proceeds of $43,701,012. This included the exercise of an over-allotment option for 1,952,100 Common Shares. Certain officers, directors and employees acquired 281,335 common shares for gross proceeds of $821,498.

During the nine months ended September 30, 2016, 16,000 stock options at $2.06 per share were exercised for total gross proceeds of $32,960. There were also 12,000 restricted share awards converted to common shares.

At September 30, 2016 there were 137,027,475 common shares, 4,382,051 options and 1,849,167 restricted share awards outstanding. At November 8, 2016 there were 137,027,475 common shares, 4,382,051 options and 1,849,167 restricted share awards outstanding. This compares to December 31, 2015 at which time there were 99,971,325 common shares, 4,668,884 options and 1,861,167 restricted share awards outstanding. The Company had 134,381,795 and 117,263,017 weighted average basic common shares outstanding during the three and nine months ended September 30, 2016. No preferred shares of the Company are issued and outstanding.

At December 31, 2015 and September 30, 2016, there were 1,155,007 preferred shares of Tamarack Acquisition Corp. ("TAC Preferred Shares") which are exchangeable into 1,110,584 commons shares of the Company. The TAC Preferred Shares are fully vested at September 30, 2016 and are exchangeable into common shares of the Company 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.

The Company currently has available a revolving credit facility in the amount of $110 million and a $10 million operating facility (collectively the "Facility") with a syndicate of lenders. The Facility totals $120 million, lasts for a 364 day period and will be subject to its next 364 day extension by May 26, 2017. If not extended on May 26, 2017, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 26, 2018. The prior revolving credit facility was $155 million. The previous borrowing base was reduced to reflect an appropriate amount of liquidity for the Company given the current commodity price environment and to save on standby and renewal fees.

The interest rate on both the revolving facility and operating facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio. The interest rate will vary 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 credit facilities. The Facility has been secured by a $300 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. The next review is scheduled to take place on November 30, 2016.

Pursuant to the terms of the Facility, the Company has provided a covenant that at all times its adjusted working capital ratio shall not be less than 1.0 to 1.0 which shall be calculated on a quarterly basis. The adjusted working capital ratio is defined under the terms of the Facility as current assets, excluding derivative assets and including the undrawn portion of the Facility, to current liabilities, excluding any current bank indebtedness and derivative liabilities. The Company is in compliance with all of its covenants.

With the recent decrease in commodity prices and continued volatility in the oil and gas industry, Tamarack's strategy remains focused on preserving balance sheet strength by adjusting capital spending relative to changes in commodity prices. The Company intends to maintain balance sheet flexibility in order to be opportunistic and take advantage of potential tuck-in acquisitions within its core areas while commodity prices are low. The equity issuance completed on March 18, 2016, and the Penny and Redwater Acquisitions and related equity issuance on July 12, 2016 were consistent with that strategy. Tamarack will focus on drilling wells that target a return on capital cost payout of 1.5 years or less. The Company will also continue to focus on reducing capital and operating costs in order to optimize capital efficiencies.

2016 Guidance

Tamarack's 2016 capital program and associated guidance is designed to meet the objective of maintaining a strong and flexible balance sheet in the context of a volatile commodity price environment. Supported by strengthening commodity prices, and concurrent with the Penny and Redwater Acquisitions, Tamarack updated its 2016 capital expenditure budget to between $45 and $53 million from $40 to $57 million, with $17 to $25 million expected to be spent during the second half of the year, assuming 2016 commodity prices averaged in the following ranges: WTI $44/bbl to $47/bbl USD, Edmonton Par price $52/bbl to $56/bbl, AECO $1.80/GJ to $2.00/GJ and a Canadian/US dollar exchange rate range of $0.77 to $0.78. Annual production guidance was increased as disclosed on June 20, 2016, to between 9,700 to 10,000 boe/d, with a target 2016 exit rate of 11,000 boe/d. Tamarack continues to maintain these guidance levels for the balance of 2016.

The Company's top priority is to maintain a strong balance sheet in order to have the flexibility to exploit opportunities that may arise in this low commodity environment including the pursuit of tuck-in acquisitions within core areas and to continue adding high quality drilling inventory. Tamarack will continue to closely monitor the broader commodity price environment and has the flexibility to accelerate or reduce capital expenditures in accordance with commodity price fluctuations from current levels.

Commitments

The following table summarizes the Company's commitments at September 30, 2016:

	2016	2017	2018	2019	2020	2021	2022	2023
Office lease	158,429	641,312	541,718	541,718	262,535	–	–	–
Take or pay commitments(1)	247,050	985,500	985,500	–	–	–	–	–
Rental fee(2)	1,292,532	5,170,125	5,170,125	5,170,125	5,170,125	5,170,125	3,299,093	714,000
Total	1,698,011	6,796,937	6,697,343	5,711,843	5,432,660	5,170,125	3,299,093	714,000

(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 31 months.

(2) Rental fee of $311,845 per month for a maximum period of 90 months starting in January 2015 relating to four facilities and rental fee of $119,000 per month for a maximum period of 90 months starting in January 2016 relating to four facilities.

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 with 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

Crude Oil		Natural Gas	
bbl	barrel	AECO	natural gas storage facility located at Suffield, AB
bbl/d	barrels per day	GJ	gigajoule
WTI	West Texas Intermediate	mcf	thousand cubic feet
		mcf/d	thousand cubic feet per day

Other	
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
NGL	natural gas liquids

Non–IFRS and Additional IFRS Measures

This document contains "funds from operations", which is an additional IFRS measure presented in the consolidated financial statements. The Company uses funds from operations as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. This document also contains the terms "net debt" and "netbacks", 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 net debt (bank debt net of working capital 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 boe basis by deducting royalties and operating costs from petroleum and natural gas sales, including realized gains and losses on commodity derivative contracts.

(a) **Funds from Operations -** Tamarack's method of calculating funds from operations may differ from other companies, and therefore may not be comparable to measures used by other companies. Tamarack calculates funds from operations as cash flow from operating activities, as determined under IFRS, before the changes in non-cash working capital related to operating activities and abandonment expenditures, as 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 as a key measure to demonstrate the Company's ability to generate funds to repay debt and fund future capital investment. Funds from operations per share have been calculated using the same basic and diluted weighted average share amounts used in earnings per share calculations. A summary of this reconciliation is presented as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
Cash provided by operating activities	**$14,085,206**	$11,738,543	**$43,128,069**	$37,939,616
Abandonment expenditures	**1,566**	(233)	**184,983**	154,574
Changes in non-cash working capital	**2,585,439**	2,879,874	**(198,757)**	3,452,410
Funds from operations	**$16,672,211**	$14,618,184	**$43,114,295**	$41,546,600
Funds from operation per share - basic	**$ 0.12**	$ 0.15	**$ 0.37**	$ 0.47
Funds from operation per share - diluted	**$ 0.12**	$ 0.15	**$ 0.37**	$ 0.47

(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 operating costs calculated on a boe basis. Management considers operating netback an important measure to evaluate its operational performance, as it demonstrates its 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):

	September 30, 2016	December 31, 2015
Cash and cash equivalents	$ –	$ –
Accounts receivables	13,980,861	15,571,507
Prepaid expenses	1,342,515	1,039,634
Accounts payable and accrued liabilities	(29,543,100)	(31,730,161)
Bank debt	(48,597,685)	(82,821,860)
Net debt	$(62,817,409)	$(97,940,880)

Selected Quarterly Information

Three months ended	**Sep. 30, 2016**	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2014
Sales volumes								
Natural gas *(mcf/d)*	**29,007**	27,462	25,818	23,229	22,005	16,972	17,864	17,518
Oil and NGL's *(bbls/d)*	**5,955**	4,959	5,279	6,096	5,049	4,163	5,115	4,761
Average boe/d *(6:1)*	**10,790**	9,536	9,582	9,968	8,717	6,992	8,092	7,681
Product prices								
Natural gas *($/mcf)*	**2.54**	1.62	2.03	2.66	3.04	2.80	2.91	3.91
Oil and NGL's *($/bbl)*	**45.29**	45.35	30.90	39.30	46.56	55.47	48.33	62.87
Oil equivalent *($/boe)*	**31.82**	28.25	22.50	30.23	34.64	39.82	34.75	47.89
(000s, except per share amounts)								
Financial results								
Gross revenues	**31,588**	24,517	19,619	27,725	27,779	25,331	25,311	33,839
Funds from operations	**16,672**	15,364	11,078	18,615	14,618	13,186	13,743	19,128
Per share – basic	**0.12**	0.13	0.11	0.19	0.15	0.16	0.18	0.25
Per share – diluted	**0.12**	0.13	0.11	0.18	0.15	0.16	0.18	0.25
Net income (loss)	**(3,195)**	(10,639)	(5,835)	5,119	(15,064)	(2,142)	(5,242)	(38,991)
Per share – basic	**(0.02)**	(0.09)	(0.06)	0.05	(0.15)	(0.03)	(0.07)	(0.50)
Per share – diluted	**(0.02)**	(0.09)	(0.06)	0.05	(0.15)	(0.03)	(0.07)	(0.50)
Additions to property and equipment, net of proceeds	**14,497**	10,310	17,149	8,743	21,936	14,246	5,028	26,774
Net property acquisitions	**85,857**	–	–	2,075	1,230	54,174	–	–
Total assets	**679,259**	542,917	553,135	549,068	549,652	561,977	482,227	497,578
Net debt[1]	**(62,817)**	(57,791)	(62,696)	(97,941)	(105,837)	(97,280)	(121,159)	(129,799)
Bank debt	**48,598**	48,630	50,056	82,822	94,423	88,500	112,951	100,200
Decommissioning obligations	**122,810**	68,149	65,643	63,331	61,808	64,883	45,340	41,357
Deferred income tax (asset)	**(41,496)**	(42,116)	(38,576)	(36,168)	(35,770)	(33,647)	(28,802)	(27,299)

(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 and net income (loss).
- The volatility in forward price curves which affects the mark-to-market calculation, and results in swings in earnings.
- The recorded impairment charges on the Company's oil and natural gas related Cash Generating Units ("CGUs") due to falling oil and gas prices in the amount of $29,100,000 in the third quarter of 2015 and $56,290,000 in the fourth quarter of 2014.
- During the third quarter of 2016, Tamarack closed two strategic acquisitions, including certain assets in the Penny area of Southern Alberta and the consolidation of assets in the Redwater and Wilson Creek areas of Alberta (the "Penny and Redwater Acquisitions") on July 12, 2016 and July

25, 2016, respectively; in 2016 these acquisitions added $6,251,289 to oil and natural gas revenue and contributed $538,060 to net loss.

- On June 15, 2015, the Company completed the Wilson Creek / Alder Flats Acquisition which added $7,266,186 to oil and natural gas revenue and contributed $1,045,845 to net loss in 2015.
- On September 30, 2014, the Company acquired 100% of the interests owned by a major oil and gas producer in the Wilson Creek area of Alberta (the "Wilson Creek Acquisition"); in 2014 this acquisition added $5,551,131 to oil and natural gas revenue and contributed $402,656 to net income.
- The Company recorded $500,000 in transaction costs in the third quarter of 2016 related to the Penny and Redwater acquisitions, $1,044,308 in transaction costs in the second and third quarters of 2015 related to the Wilson Creek / Alder Flats Acquisition and $3,820,275 in transaction costs in the third and fourth quarter of 2014 related to the Wilson Creek Acquisition.

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) **Depletion, depreciation, amortization and impairment –** Property, plant and equipment is measured at cost less accumulated depletion, depreciation, amortization, and impairment losses. The net carrying value of property, plant and equipment 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 exploration and evaluation assets or development and production assets within property, plant and equipment. Exploration and evaluation 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.

Exploration and evaluation 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. Exploration and evaluation assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined 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, by comparing the relevant costs to the fair value of CGUs, aggregated at the segment level. The determination of the fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating 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 property, plant and equipment 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 fair value of CGUs requires the use of assumptions and estimates including quantities of recoverable reserves, production quantities, future commodity prices and development and operating 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.

(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 property, plant and equipment and amortized over its useful life. 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) **Share-based compensation –** The Company uses the fair value method for valuing stock option and preferred share grants. Under this method, compensation cost attributable to all share options and preferred shares 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 preferred shares 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 net 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.

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 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 quarter ended September 30, 2016 that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

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

Business Risks

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

Financial Risks

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

Commodity price fluctuations result from market forces completely out of the Company's control and can significantly affect the Company's financial results. In addition, fluctuations between the Canadian dollar and the US dollar can also have a significant impact. Expenses are all incurred in Canadian dollars while crude oil, and to some extent natural gas, prices are based on reference prices denominated in US dollars. As a result of 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 interruption, including well blow-outs and pollution. In addition, Tamarack cultivates long-term relationships with its suppliers in an effort to ensure good service regardless of the current 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 cost-effectively.

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 securities laws. 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", "continue", "estimate", "expect", "forecast", "may", "will", "can", "potential", "target", "intend", "focus", "identify", "manage", "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.

In particular, this MD&A contains forward-looking statements pertaining to:

- The proposed Combination including the impact of the Combination on Tamarack and Tamarack's plans

- The timing and anticipated closing date for the Combination, including anticipated receipt of all closing regulatory and shareholder approval in respect of the Combination
- Anticipated Combination value, the effect of the Combination, estimated future drilling locations and estimated debt, allocation of capital and timing of the drilling program and capital expenditures
- Estimated production rates in 2016 and 2017.
- Future operating costs.
- Reduction of production expenses on an absolute and per boe basis in the fourth quarter of 2016 for the Penny and Redwater Assets.
- Tamarack's focus on preserving balance sheet strength by adjusting capital spending relative to commodity prices and reducing operating costs on newly acquired assets.
- Tamarack's primary focus areas for production growth.
- Future drilling plans.
- Deferred tax liabilities.
- The timing of review of the Facility.
- Future capital expenditures and capital program funding.
- The Company's capital program and guidance for 2016.
- Derivative contracts and Tamarack's commodity price and foreign exchange rate risk management activities.
- Expectations as to oil and natural gas pricing in 2016.
- Expectations as to oil and natural gas weighting in 2016.
- Expectations as to royalty rates in 2016 and the implementation of the MRF by the Government of Alberta.
- The ability of the Company to take advantage of opportunities that may arise while commodity prices are low.

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

- future commodity prices;
- expected operating costs;
- estimated reserves of oil and natural gas;
- timely receipt of all shareholder, court and regulatory approval for the Combination
- successful completion of the Combination and satisfaction of other closing conditions in accordance with the terms of the arrangement agreement with Spur Resources Ltd.
- 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 or the Combination or the acquisition of undeveloped lands Tamarack considers prospective for hydrocarbons;

- 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
- 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 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 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;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- marketing and transportation;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- the ability to access sufficient capital from internal and external sources; and
- changes in tax, royalty and environmental legislation.

In addition, the completion of the Combination could be delayed if parties are unable to obtain the necessary regulatory, stock exchange, shareholder and court approvals on the timeline planned. The Combination will not be completed if all of these approvals are not obtained or other conditions of closing are not satisfied. Accordingly, there is a risk that the Combination will not be completed within the anticipated time or at all.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. 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, 2015, 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.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets

(unaudited)

	September 30, 2016	December 31, 2015
Assets		
Current assets:		
Accounts receivable	$13,980,861	$15,571,507
Prepaid expenses and deposits	1,342,515	1,039,634
Fair value of financial instruments (note 3)	–	12,468,101
	15,323,376	29,079,242
Property, plant and equipment (note 5)	619,279,274	481,615,900
Exploration and evaluation assets (note 6)	3,160,123	2,204,978
Deferred tax asset	41,495,766	36,167,594
	$679,258,539	$549,067,714
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$29,543,100	$31,730,161
Fair value of financial instruments (note 3)	3,047,721	–
	32,590,821	31,730,161
Bank debt (note 11)	48,597,685	82,821,860
Decommissioning obligations (note 7)	122,809,767	63,330,850
Shareholders' equity:		
Share capital (note 9)	535,820,463	416,075,358
Contributed surplus	20,773,415	17,044,404
Deficit	(81,333,612)	(61,934,919)
	475,260,266	371,184,843
Commitments and contingencies (note 13)		
Subsequent event (note 14)		
	$679,258,539	$549,067,714

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Loss and Comprehensive Loss
For the three and nine months ended September 30, 2016 and 2015
(unaudited)

	Three Months ended September 30,		Nine Months ended September 30,	
	2016	2015	2016	2015
Revenue:				
Oil and natural gas	$31,588,087	$27,779,319	$75,723,734	$78,420,495
Royalties	(2,219,838)	(3,051,720)	(5,049,197)	(8,000,773)
Realized gain on financial instruments (note 3)	2,082,980	4,288,134	12,458,959	9,987,577
Unrealized gain (loss) on financial instruments (note 3)	(528,632)	11,297,903	(15,515,822)	3,960,284
	30,922,597	40,313,636	67,617,674	84,367,583
Expenses:				
Production	11,493,859	11,264,333	31,241,159	28,313,619
General and administration	1,872,202	1,733,423	5,405,294	5,458,800
Transaction costs	500,000	12,791	596,254	1,044,308
Stock-based compensation (note 12)	826,863	699,933	2,688,815	2,297,279
Finance	1,409,196	1,654,594	3,945,728	4,752,586
Depletion, depreciation and amortization	17,107,627	14,074,094	47,535,942	43,733,433
Loss (gain) on disposition of property, plant and equipment	–	(231,881)	–	180,207
Impairment of property, plant and equipment	–	29,100,000	–	29,100,000
	33,209,747	58,307,287	91,413,192	114,880,232
Loss before taxes	(2,287,150)	(17,993,651)	(23,795,518)	(30,512,649)
Deferred income tax recovery (expense)	(907,707)	2,929,781	4,396,825	8,065,362
Net loss and comprehensive loss	$(3,194,857)	$(15,063,870)	$(19,398,693)	$(22,447,287)
Net loss per share (note 10):				
Basic	$(0.02)	$(0.15)	$(0.17)	$(0.26)
Diluted	$(0.02)	$(0.15)	$(0.17)	$(0.26)

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Changes in Equity
(unaudited)

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2016	99,971,325	$416,075,358	$17,044,404	$(61,934,919)	$371,184,843
Issue of common shares	35,104,150	117,336,755	–	–	117,336,755
Issue of flow-through shares	1,952,000	8,003,200	–	–	8,003,200
Share issue costs, net of tax of $1,790,227	–	(4,840,241)	–	–	(4,840,241)
Transfer on exercise of stock options	–	104,271	(104,271)	–	–
Flow-through share premium	–	(858,880)	–	–	(858,880)
Stock-based compensation	–	–	3,833,282	–	3,833,282
Net loss	–	–	–	(19,398,693)	(19,398,693)
Balance at September 30, 2016	137,027,475	$535,820,463	$20,773,415	$(81,333,612)	$475,260,266

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders' equity
Balance at January 1, 2015	77,928,466	$336,086,662	$12,931,358	$(44,606,551)	$304,411,469
Issue of common shares	19,818,459	74,860,360	–	–	74,860,360
Issue of flow-through shares	2,186,800	9,075,220	–	–	9,075,220
Share issue costs, net of tax of $1,215,369	–	(3,537,078)	–	–	(3,537,078)
Transfer on exercise of stock options and preferred shares	–	247,906	(247,906)	–	–
Flow-through share premium	–	(809,116)	–	–	(809,116)
Stock-based compensation	–	–	3,429,487	–	3,429,487
Net loss	–	–	–	(22,447,287)	(22,447,287)
Balance at September 30, 2015	99,933,725	$415,923,954	$16,112,939	$(67,053,838)	$364,983,055

See accompanying note to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three and nine months ended September 30, 2016 and 2015
(unaudited)

	Three Months ended September 30,		Nine Months ended September 30,	
	2016	2015	2016	2015
Cash provided by (used in):				
Operating:				
Net loss	$(3,194,857)	$(15,063,870)	$(19,398,693)	$(22,447,287)
Items not involving cash:				
Depletion, depreciation and amortization	17,107,627	14,074,094	47,535,942	43,733,433
Stock-based compensation	826,863	699,933	2,688,815	2,297,279
Loss (gain) on disposition of property, plant and equipment	–	(231,881)	–	180,207
Accretion expense on decommissioning obligations	496,239	267,592	1,169,234	708,614
Unrealized loss (gain) on financial instruments	528,632	(11,297,903)	15,515,822	(3,960,284)
Impairment of property, plant and equipment	–	29,100,000	–	29,100,000
Deferred income tax expense (recovery)	907,707	(2,929,781)	(4,396,825)	(8,065,362)
Funds from operations	16,672,211	14,618,184	43,114,295	41,546,600
Abandonment expenditures (note 7)	(1,566)	233	(184,983)	(154,574)
Changes in non-cash working capital (note 8)	(2,585,439)	(2,879,874)	198,757	(3,452,410)
Cash provided by operating activities	14,085,206	11,738,543	43,128,069	37,939,616
Financing:				
Change in bank debt	(32,139)	5,923,028	(34,224,175)	(5,776,972)
Proceeds from issuance of shares	81,605,983	–	125,339,955	83,935,580
Share issue costs	(4,246,517)	(9,845)	(6,630,468)	(4,752,447)
Cash provided by financing activities	77,327,327	5,913,183	84,485,312	73,406,161
Investing:				
Property, plant and equipment additions	(13,972,077)	(22,158,281)	(39,713,209)	(43,239,213)
Exploration and evaluation additions	(525,311)	(69,443)	(2,243,026)	(218,507)
Acquisitions (note 4)	(85,308,155)	(1,230,258)	(85,308,155)	(56,213,342)
Proceeds from disposal of property, plant and equipment	–	292,354	–	2,247,937
Changes in non-cash working capital (note 8)	8,393,010	2,085,460	(348,991)	(14,752,756)
Cash used in investing activities	(91,412,533)	(21,080,168)	(127,613,381)	(112,175,881)
Change in cash and cash equivalents	–	(3,428,442)	–	(830,104)
Cash and cash equivalents, beginning of period	–	3,428,442	–	830,104
Cash and cash equivalents, end of period	$ –	$ –	$ –	$ –

See accompanying notes to the condensed consolidated interim financial statements.

1. Reporting entity:

Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") is a corporation existing under the laws of Alberta. The condensed consolidated interim financial statements of Tamarack consist of the Company and its subsidiaries. The Company has the following wholly owned subsidiaries, which are incorporated in Canada: Tamarack Acquisition Corp. and Tamarack Valley Ridge Holdings Ltd. The Company also has a subsidiary incorporated in the United States: Tamarack Ridge Resources Inc. On January 1, 2016, Tamarack Acquisition Corp. and Tamarack Valley Holdings Corp., completed a vertical amalgamation under the *Business Corporations Act* (Alberta) to form "Tamarack Acquisition Corp". The Company is engaged in the exploration for, development and production of, oil and natural gas.

Tamarack is a publicly traded company, incorporated and domiciled in Canada. The address of its registered office is Suite 2500, 450 – 1st Street S.W., Calgary, Alberta, T2P 5H1. The address of its head office is currently Suite 600, 425 – 1st Street S.W., Calgary, Alberta T2P 3L8.

2. Basis of preparation:

(a) Statement of compliance:

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

These condensed consolidated interim financial statements have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company for the year ended December 31, 2015. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These condensed consolidated interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company's annual filings for the year ended December 31, 2015.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on November 7, 2016.

3. Commodity contracts:

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

All financial derivative contracts are classified as fair value through profit and loss and are recorded on the balance sheet at fair value. The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and level 2 published forward price curves as at the balance sheet date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and collars is based on option models that use level 2 inputs, being published information with respect to volatility, prices and interest rates. The derivatives are valued at fair value to profit and loss and therefore carrying amount equals fair value.

At September 30, 2016, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn $)
Crude oil	2,000 bbls/day	October 1, 2016 – December 31, 2016	WTI fixed price	Cdn $66.43	$392,024
Crude oil	2,200 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $60.54	($1,124,467)
Crude oil	2,200 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $61.60	($1,161,940)
Crude oil	1,000 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $64.35	($348,011)
Crude oil	200 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $67.45	($24,332)
Natural gas	3,000 GJ/day	October 1, 2016 – October 31, 2016	AECO fixed price	Cdn $2.53	$33,861
Natural gas	9,000 GJ/day	October 1, 2016 – December 31, 2016	AECO fixed price	Cdn $2.31	($242,513)
Natural gas	12,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.68	($182,547)
Natural gas	12,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.37	($189,969)
Natural gas	12,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.41	($161,980)
Natural gas	9,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $2.79	($37,847)
					($3,047,721)

At September 30, 2016, the commodity contracts were fair valued with a liability of $3,047,721 (December 31, 2015 - $12,468,101 asset) recorded on the balance sheet and an unrealized loss of $15,515,822 recorded in earnings.

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement the realized benefit or loss is recognized in oil and natural gas revenue. At September 30, 2016, the Company held physical commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Natural gas	2,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.55

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

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

Gross Amounts	**September 30, 2016**	December 31, 2015
Risk management contracts		
Current asset	**$425,885**	$12,468,101
Current liability	**($3,473,606)**	–
Balance, end of the period	**($3,047,721)**	$12,468,101

Since September 30, 2016, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	200 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $68.55
Crude oil	200 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $70.00
Natural gas	2,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $3.20
Natural gas	4,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.81
Natural gas	2,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.78

4. Property Acquisitions:

On July 12, 2016, the Company acquired certain working interests in developed petroleum and natural gas properties in the Penny area of Southern Alberta (“Penny Acquisition”) for an aggregate cash purchase price of approximately $59.1 million after closing adjustments.

On July 25, 2016, the Company acquired certain working interests in developed petroleum and natural gas properties in the Redwater and Wilson Creek areas of Alberta (“Redwater Acquisition”) for an aggregate cash purchase price of approximately $27.3 million after closing adjustments.

The Penny Acquisition represents a new core area for the Company focused on Barons oil, while the Redwater Acquisition complements the Company’s existing Viking oil properties. The operations from the acquisitions have been included in the results of the Company commencing in July of 2016. The Company incurred transaction costs of $500,000, which were expensed through the statement of income and comprehensive income.

The acquisitions have been accounted for as business combinations and the allocation of the purchase price is as follows:

Consideration:	**Penny Acquisition**	**Redwater Acquisition**	**Total**
Cash	$ 59,074,517	$ 26,233,638	$ 85,308,155
Working capital settled	–	1,095,880	1,095,880
Total consideration	$ 59,074,517	27,329,518	$ 86,404,035

Net Assets Acquired:			
Prepaid expenses	$ 948,191	$ 896,751	$ 1,844,942
Property, plant and equipment	67,714,156	37,626,509	105,340,665
Decommissioning obligations	(9,587,830)	(11,193,742)	(20,781,572)
Net assets	$ 59,074,517	$ 27,329,518	$ 86,404,035

The above amounts are estimates, which were made by management at the time of preparation of these financial statements based on information then available. Amendments may be made to these amounts as values subject to estimate are finalized.

The fair value of property, plant and equipment has been determined with reference to a reserve report. The fair value of decommissioning obligations was initially estimated using a credit adjusted rate of 8%.

Included in the statement of income are the following amounts for the Penny and Redwater Acquisitions since the date of acquisitions:

	Penny Acquisition	Redwater Acquisition	Total
Oil and natural gas revenue	$3,911,986	$2,339,903	$6,251,289
Net loss	(89,119)	(448,941)	(538,060)

If the Penny and Redwater properties had been acquired on January 1, 2016, the incremental oil and natural gas revenue and income recognized for the period ended September 30, 2016 and the pro forma results would have been as follows:

Period ended September 30, 2016	As stated	Penny Acquisition prior to acquisition	Redwater Acquisition prior to acquisition	Pro Forma
Oil and natural gas revenue	$75,723,734	$9,603,285	$6,220,459	$91,547,478
Net loss	(19,398,693)	(671,954)	(4,596,797)	(24,667,444)

5. Property, plant and equipment:

	Oil and Natural Gas Interests	Other Assets	Total
Cost:			
Balance at January 1, 2015	$585,493,847	$332,484	$585,826,331
Property acquisition	66,716,576	–	66,716,576
Cash additions	61,490,520	268,747	61,759,267
Decommissioning costs	12,207,496	–	12,207,496
Stock-based compensation	1,419,207	–	1,419,207
Transfer from exploration and evaluation assets	1,989,039	–	1,989,039
Disposals	(12,928,641)	–	(12,928,641)
Balance at December 31, 2015	716,388,044	601,231	716,989,275
Property acquisition	105,340,665	–	105,340,665
Cash additions	39,357,909	355,300	39,713,209
Decommissioning costs	37,713,094	–	37,713,094
Stock-based compensation	1,144,467	–	1,144,467
Transfer from exploration and evaluation assets	730,863	–	730,863
Balance at September 30, 2016	$900,675,042	$956,531	$901,631,573
Depletion, depreciation and impairment losses:			
Balance at January 1, 2015	$150,320,639	$177,576	$150,498,215
Depletion and depreciation	58,744,439	87,101	58,831,540
Disposals	(131,380)	–	(131,380)
Impairment loss	26,175,000	–	26,175,000
Balance at December 31, 2015	235,108,698	264,677	235,373,375
Depletion and depreciation	46,864,473	114,451	46,978,924
Balance at September 30, 2016	$281,973,171	$379,128	$282,352,299

	Oil and Natural Gas Interests	Other Assets	Total
Carrying amounts:			
At December 31, 2015	$481,279,346	$336,554	$481,615,900
At September 30, 2016	$618,701,871	$577,403	$619,279,274

The calculation of depletion at September 30, 2016 includes estimated future development costs of $407,368,000 (December 31, 2015 – $361,667,000) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $32,178,000 (December 31, 2015 – $25,630,400).

6. Exploration and evaluation assets:

	Total
Cost:	
Balance at January 1, 2015	$23,631,049
Additions	440,838
Transfer to property, plant and equipment	(1,989,039)
Balance at December 31, 2015	22,082,848
Additions	2,243,026
Transfer to property, plant and equipment	(730,863)
Balance at September 30, 2016	$23,595,011
Amortization and impairment:	
Balance at January 1, 2015	$19,162,226
Amortization	715,644
Balance at December 31, 2015	19,877,870
Amortization	557,018
Balance at September 30, 2016	$ 20,434,888

	Total
Carrying amounts:	
At December 31, 2015	$2,204,978
At September 30, 2016	$3,160,123

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

7. 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 amount of cash flows required to settle its decommissioning obligations to be approximately $115.7 million at September 30, 2016 (December 31, 2015 – $63.0 million), which is expected to be incurred between 2016 and 2038. A risk-free rate of 1.80% (2015 – 2.2%) and an inflation rate of 2% (2015 – 2%) is used to calculate the fair value of the decommissioning obligations at September 30, 2016 as presented in the table below:

	September 30, 2016	December 31, 2015
Balance, beginning of the period	**$63,330,850**	$41,356,532
Liabilities incurred	**1,015,265**	1,091,390
Liabilities acquired (note 4)	**20,781,572**	9,237,544
Change in estimates	**3,652,674**	444,130
Change in discount rate on acquisition	**33,045,155**	10,671,976
Expenditures	**(184,983)**	(155,559)
Liabilities disposed	–	(369,117)
Accretion	**1,169,234**	1,053,954
Balance, end of the period	**$122,809,767**	$63,330,850

The decommissioning obligations acquired in the Penny and Redwater Acquisitions were initially recognized using a fair value discount rate of 8%. They were subsequently revalued using the risk-free rate noted above resulting in the change in discount rate on acquisition in the above table with the offset to property, plant and equipment.

A change in estimates for 2016 resulted from the decommissioning obligations being revalued using the risk-free rate of 1.8% as opposed to the risk free rate of 2.2% used in 2015.

8. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
Source/(use of cash):				
Accounts receivable	**$(136,040)**	$(399,885)	**$1,590,646**	$4,232,638
Prepaid expenses and deposits	**(362,769)**	(63,082)	**(302,881)**	(74,448)
Accounts payable and accrued liabilities	**5,557,318**	(331,447)	**(2,187,061)**	(23,172,790)
Working capital on acquisition (note 4)	**749,062**	–	**749,062**	809,434
	$5,807,601	$(794,414)	**$(150,234)**	$(18,205,166)
Related to operating activities	**$(2,585,439)**	$(2,879,874)	**$198,757**	$(3,452,410)
Related to investing activities	**$8,393,010**	$2,085,460	**$(348,991)**	$(14,752,756)

9. Share capital:

At September 30, 2016 the Company was authorized to issue an unlimited number of common shares and preferred shares without nominal or par value.

On July 12, 2016, the Company completed a bought deal financing by issuing 20,110,050 common shares at $3.66 per share for total gross proceeds of $73,602,783. This included an over-allotment option that was exercised for 2,623,050 common shares. Certain officers, directors and employees acquired 99,950 common shares for gross proceeds of $365,817.

On July 12, 2016, the Company also issued 1,952,000 flow-through common shares, related to Canadian development expenditures, at $4.10 per share for total gross proceeds of $8,003,200. Certain officers, directors and employees acquired 4,900 flow-through common shares for gross proceeds of $20,090. Under the terms of the flow-through share agreements, the Company is required to renounce and incur the $8,003,200 of qualifying oil and natural gas expenditures effective December 31, 2016. As of September 30, 2016 the Company has incurred the full amount of qualifying oil and natural gas expenditures.

On March 18, 2016, the Company completed a bought deal financing by issuing 14,966,100 common shares at $2.92 per share for total gross proceeds of $43,701,012. This included an over-allotment option that was exercised for 1,952,100 common shares. Certain officers, directors and employees acquired 281,335 common shares for gross proceeds of $821,498.

During the nine months ended September 30, 2016 16,000 stock options at $2.06 per share were exercised for gross proceeds of $32,960. There were also 12,000 restricted share awards converted to common shares.

10. Income (loss) per share:

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

	Three months ended September 30,		Nine months ended September 30,	
	2016	2015	**2016**	2015
Net loss	**$(3,194,857)**	$(15,063,870)	**$(19,398,693)**	$(22,447,287)
Weighted average shares - basic	**134,381,795**	99,933,725	**117,263,018**	87,532,408
Weighted average shares - diluted	**134,381,795**	99,933,725	**117,263,018**	87,532,408
Net loss per share-basic	**$(0.02)**	$(0.15)	**$(0.17)**	$(0.26)
Net loss per share-diluted	**$(0.02)**	$(0.15)	**$(0.17)**	$(0.26)

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three and nine months ended September 30, 2016, 7,612,635 stock options, preferred shares and restrictive stock units were excluded from the diluted earnings per share as they were anti-dilutive. For the three and nine months ended September 30, 2015, 5,700,635 stock options, preferred shares and restrictive stock units were excluded from the diluted earnings per share as they were anti-dilutive.

11. Bank debt:

The Company currently has available a revolving credit facility in the amount of $110 million and a $10 million operating facility (collectively the "Facility") with a syndicate of lenders. The Facility totaling $120 million lasts for a 364 day period and will be subject to its next 364 day extension by May 26, 2017. If not extended on May 26, 2017, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 26, 2018.

The interest rate on both the revolving facility and operating facility is determined through a pricing grid that categorizes based on a net debt to cash flow ratio. The interest rate will vary 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 credit facilities. The Facility has been secured by a $300 million supplemental debenture with a floating charge over all assets. As the available lending limits of the Facility are based on the bank's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available facilities that will be determined at each scheduled review. The next review is scheduled to take place on November 30, 2016.

Pursuant to the terms of the Facility, the Company has provided a covenant that at all times its adjusted working capital ratio shall not be less than 1.0 to 1.0. The adjusted working capital ratio is defined under the terms of the credit facilities as current assets excluding derivative assets, including the undrawn portion of the Facility, to current liabilities, excluding any current bank indebtedness and derivative liabilities.

At September 30, 2016, the Company had utilized the Facility in the amount of $48.6 million and the Company was compliant with its working capital ratio at 2.9 to 1.0. As at September 30, 2016, the Company had letter of guarantees outstanding in the amount of $43,980 against the Facility.

12. Share-based payments:

(a) Preferred share plan:

There are 1,155,007 preferred shares of Tamarack Acquisition Corp. outstanding which are exchangeable into 1,110,584 common shares of the Company (December 31, 2015 – 1,110,584). The preferred shares of Tamarack Acquisition Corp. are fully vested at September 30, 2016 and are exchangeable into common shares of the Company at an exchange price of $3.12 per common share. An exchange of the preferred shares is at the election of the Company under certain circumstances.

(b) Stock option plan:

Under the Company's stock option and restricted share unit plan it may grant up to 13,702,748 options or restricted share units to its employees, directors and consultants of which 6,823,948 options, preferred shares and restricted stock units have been issued that apply against this maximum amount. Stock options are granted at the market price of the shares at the date of grant, have a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant. There were no options granted during the period.

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

	Number of options	Weighted average exercise price
Outstanding, January 1, 2015	4,147,386	$ 3.70
Granted	727,000	2.84
Exercised	(29,167)	3.60
Forfeited	(134,668)	2.94
Expired	(41,667)	4.44
Outstanding, December 31, 2015	4,668,884	$ 3.59
Exercised	(16,000)	2.06
Expired	(270,833)	4.55
Outstanding, September 30, 2016	4,382,051	$ 3.53

The following table summarizes information about stock options outstanding and exercisable at September 30, 2016:

	Options outstanding			Options exercisable	
Range of exercise price	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable	Weighted average exercise price
$ 1.86 – 3.00	1,737,051	$2.35	2.2	1,100,384	$2.13
$ 3.01 – 5.00	2,179,000	$3.77	2.3	1,369,667	$3.72
$ 5.01 – 6.82	466,000	$6.82	2.9	310,667	$6.82
$ 1.86 – 6.82	**4,382,051**	**$3.53**	**2.3**	**2,780,718**	**$3.44**

(c) Restricted stock unit plan

The Company has a restricted stock unit plan that allows the board of directors to grant restricted share awards to directors, officers and employees. Subject to terms and conditions of the restricted stock unit plan, each restricted share award entitles the holder to an award value to be paid as to one-third on each of the first, second and third anniversaries of the date of grant.

The following table summarizes information about the restricted share awards:

	Number of awards
Outstanding, January 1, 2015	406,500
Granted	1,459,000
Exercised	(4,333)
Outstanding, December 31, 2015	1,861,167
Exercised	(12,000)
Outstanding, September 30, 2016	1,849,167

13. Commitments and contingencies:

(a) Commitments

The following table summarizes the Company's commitments at September 30, 2016:

	2016	2017	2018	2019	2020	2021	2022	2023
Office lease	158,429	641,312	541,718	541,718	262,535	–	–	–
Take or pay commitments[(1)]	247,050	985,500	985,500	–	–	–	–	–
Rental fee[(2)]	1,292,532	5,170,125	5,170,125	5,170,125	5,170,125	5,170,125	3,299,093	714,000
Total	1,698,011	6,796,937	6,697,343	5,711,843	5,432,660	5,170,125	3,299,093	714,000

(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 31 months.

(2) Rental fee of $311,845 per month for a maximum period of 90 months starting in January 2015 relating to four facilities and rental fee of $119,000 per month for a maximum period of 90 months starting in January 2016 relating to four facilities.

(b) Contingencies

The Company, in the normal course of operations, will occasionally become subject to a variety of legal and other claims. Management and the Company's legal counsel evaluate all claims and as necessary, access management's best estimate of costs, if any, to satisfy such claims.

14. Subsequent event:

On November 2, 2016, Tamarack announced an arrangement agreement (the "Arrangement Agreement") providing for the acquisition by Tamarack of all of the issued and outstanding common shares of Spur Resources Ltd., which will hold Spur's Viking oil assets at closing (the "Combination"). This transaction will build upon the Company's existing Viking asset base at Redwater and core Cardium assets at Wilson Creek. Under the terms of the Arrangement Agreement, Tamarack will issue an aggregate of approximately 90.1 million common shares of Tamarack and a fixed portion of $57.3 million in cash. Tamarack will also be assuming Spur's net debt, estimated to be $25.7 million as at November 30, 2016, after accounting for proceeds from the exercise of all outstanding options of Spur, and severance and transaction costs. Any variance in net debt from the $25.7 million at November 30, 2016 until closing will adjust the purchase price. Based upon the previous 10-day volume weighted average price at November 2, 2016, of Tamarack of $3.60 per share, the total consideration payable by Tamarack, including the assumption of debt, will be approximately $407.5 million. The estimates for share price will be determined at the time of closing along with the other estimates noted above.

Closing of the Combination is expected to occur on or about January 11, 2017 and is subject to the receipt by Tamarack and Spur of all court, stock exchange and other regulatory approvals, receipt of the requisite shareholder approvals of Tamarack and Spur, no material adverse change having occurred in Spur and a number of other matters customary in transactions of this nature. All directors and officers of Spur, representing approximately 34% of the issued and outstanding Spur Shares, have entered into support agreements with Tamarack pursuant to which they have agreed to vote their Spur Shares in favor of the Combination.

CORPORATE INFORMATION

Directors

Floyd Price - Chairman(1)(2)(3)

Dean Setoguchi(1)(3)

David Mackenzie(1)(2)

Jeff Boyce(2)(3)

Noralee Bradley(3)

Brian Schmidt

(1) Member of 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

Lead Bank Syndicate

National Bank of Canada

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange
Stock symbol: TVE

Management Team

Brian Schmidt
President & Chief Executive Officer

Ron Hozjan
VP Finance & Chief Financial Officer

Dave Christensen
VP Engineering

Ken Cruikshank
VP Land

Kevin Screen
VP Production & Operations

Scott Reimond
VP Exploration

Rummy Basra
Corporate Secretary

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