MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the three months ended March 31, 2016 and 2015. This MD&A is dated and based on information available on May 10, 2016 and should be read in conjunction with the unaudited condensed consolidated interim financial statements and notes for the three months ended March 31, 2016 and 2015. Additional information relating to Tamarack, including Tamarack's annual information form, is available on SEDAR at www.sedar.com.

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 12 and 13. 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.

Production

	Three months ended March 31,		
	2016	2015	% change
Production			
Light oil (bbls/d)	**3,802**	4,029	(6)
Heavy oil (bbls/d)	**410**	498	(18)
Natural gas liquids (bbls/d)	**1,067**	588	81
Natural gas (mcf/d)	**25,818**	17,864	45
Total (boe/d)	**9,582**	8,092	18
Percentage of oil and natural gas liquids	**55%**	63%	

Relative to the fourth quarter of 2015, Tamarack expected that production in 2016 would decline as a result of the decision to defer $6 to $8 million of capital into the second half of 2016 in response to ongoing low commodity prices. Based on commodity prices realized during the first quarter of 2016, the Company was operating on the premise that it would spend on the lower end of its $40 million to $57 million capital budget. The Company will continue to monitor the price environment, and could elect to accelerate its capital spending in the second half of 2016, should commodity prices continue to strengthen. The Company still expects production in the first half of 2016 to average between 9,100 and 9,600 boe/d. See page 11 for a more comprehensive summary of 2016 guidance.

As expected, average production for the first quarter of 2016 decreased by 4% to 9,582 boe/d from 9,968 boe/d in the fourth quarter of 2015. The production decrease was mainly the result of normal declines from existing production, partially offset by 5 (4.3 net) Cardium oil wells and by 1 (0.8 net) Manville gas well which came on stream late in the quarter and added 531 boe/d in the quarter.

Crude oil and natural gas liquids production in the first quarter of 2016 decreased 13% to average 5,279 bbls/d compared to 6,096 bbls/d in the fourth quarter of 2015. The production decrease was primarily due to normal declines from existing production and partially offset by the 5 (4.3 net) Cardium oil wells which came on stream late in the quarter and averaged 143 bbls/d of oil and liquids production over the quarter.

Tamarack's first quarter 2016 oil and natural gas liquids weighting decreased to 55% of total production compared to 61% during the fourth quarter of 2015. During 2016, the Company expects its oil and natural gas liquids weighting to fluctuate between 50% and 55% depending on the timing of production additions from the Wilson Creek area where production will have a higher liquids weighting compared to the Alder Flats and Brazeau areas, which have a higher natural gas weighting. Oil and natural gas weighting may also be affected by production additions from Mannville gas wells.

Natural gas production averaged 25,818 mcf/d in the first quarter of 2016 compared to 23,229 mcf/d in the fourth quarter of 2015. The production increase was mainly the result of associated gas production from the 5 (4.3 net) Cardium oil wells and 1 (0.8 net) Mannville gas well, all of which came on stream late in the quarter adding 2,325 mcf/d to the period's production. This volume increase was partially offset by normal declines from existing production.

Compared to the prior year, average first quarter 2016 production increased by 18% to 9,582 boe/d from 8,092 boe/d in the same period in 2015. This increase is attributable to several factors, including production from assets acquired in the Alder Flats area of Alberta in the second quarter of 2015 (the "Alder Flats Acquisition") and the successful 2016 first quarter drilling program, all of which were partially offset by expected declines from existing production.

Petroleum, Natural Gas Sales and Royalties

	Three months ended March 31		
	2016	2015	% change
Revenue			
Oil and NGLs	**$14,843,324**	$20,628,395	(28)
Natural gas	**4,775,335**	4,682,238	2
Total	**$19,618,659**	$25,310,633	(22)
Average realized price			
Light oil ($/bbl)	**36.82**	48.33	(24)
Heavy oil ($/bbl)	**23.32**	39.18	(40)
Natural gas liquids ($/bbl)	**12.71**	25.43	(50)
Combined average oil and NGLs ($/boe)	**30.90**	44.81	(31)
Natural gas ($/mcf)	**2.03**	2.91	(30)
Revenue ($/boe)	**22.50**	34.75	(35)
Benchmark pricing:			
Edmonton Par (Cdn$/bbl)	**36.79**	52.60	(30)
Hardisty Heavy (Cdn$/bbl)	**24.74**	42.64	(42)
AECO daily index (Cdn$/mcf)	**1.83**	2.76	(34)
AECO monthly index (Cdn$/mcf)	**2.10**	2.94	(28)
Royalty expenses	**$1,780,362**	$2,756,164	(35)
$/boe	**2.04**	3.78	(46)
percent of sales	**9**	11	(18)

Revenue from crude oil, natural gas and associated natural gas liquids sales was $19,618,659 in the first quarter of 2016, a 29% decrease from $27,725,228 in the fourth quarter of 2015. This is attributable to a 13% decrease in crude oil and natural gas liquids production combined with prices that were 24% and 21% lower for natural gas and crude oil and natural gas liquids, respectively, offset by an 11% increase in natural gas production. First quarter 2016 revenue was 22% lower than the $25,310,633 realized in the first quarter of 2015 primarily due to a 31% decrease in crude oil and natural gas liquids pricing and a 30% decrease in natural gas prices, partially offset by production increases of 3% for crude oil and natural gas liquids and 45% for natural gas. During the first quarter of 2016, natural gas prices averaged $2.03/mcf and the combined oil and natural gas liquids prices averaged $30.90/bbl, compared to $2.66/mcf and $39.30/bbl in the fourth quarter of 2015 and $2.91/mcf and $44.81/bbl in the first quarter of 2015, respectively.

The Company's realized crude oil prices for the three months ended March 31, 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 months ended March 31, 2016 and 2015 generally correlate to the Hardisty Heavy price for those periods.

For the three months ended March 31, 2016, Tamarack's realized natural gas prices generally correlate to AECO daily index pricing, but may not always correlate to AECO monthly index pricing. This variance 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 March 31, 2016, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	2,400 bbls/day	April 1, 2016 – June 30, 2016	WTI fixed price	Cdn $76.21
Crude oil	1,800 bbls/day	July 1, 2016 – September 30, 2016	WTI fixed price	Cdn $69.92
Crude oil	1,700 bbls/day	October 1, 2016 – December 31, 2016	WTI fixed price	Cdn $66.66
Crude oil	900 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $56.99
Crude oil	900 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $58.17
Natural gas	3,000 GJ/day	April 1, 2016 – October 31, 2016	AECO fixed price	Cdn $2.53
Natural gas	4,000 GJ/day	October 1, 2016 – December 31, 2016	AECO fixed price	Cdn $2.29
Natural gas	6,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.61

At March 31, 2016, the commodity contracts were fair valued with an asset of $10,363,977 (December 31, 2015 - $12,468,101) recorded on the balance sheet and an unrealized loss of $2,104,124 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 March 31, 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	April 1, 2016 – June 30, 2016	AECO fixed price	Cdn $2.40
Natural gas	2,000 GJ/day	July 1, 2016 – August 31, 2016	AECO fixed price	Cdn $2.44

Since March 31, 2016, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	600 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $61.12
Crude oil	400 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $61.53
Crude oil	200 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $62.00
Natural gas	3,000 GJ/day	October 1, 2016 – December 31, 2016	AECO fixed price	Cdn $2.25
Natural gas	2,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.55
Natural gas	10,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.34
Natural gas	7,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.37

Since March 31, 2016, the Company has entered into the following physical commodity contracts:

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

Royalty expenses for the first quarter of 2016 were $2.04/boe or $1,780,362, representing 9% of revenue, compared to $2.80/boe or $2,564,759 for the fourth quarter of 2015, representing 9% of revenue. The $0.76/boe decrease in royalties in the first quarter of 2016 compared to the fourth quarter of 2015 was related to the continued fall in commodity prices.

For the first quarter of 2015, royalty expenses were $3.78/boe or $2,756,164, representing 11% of revenue.

Compared to the first quarter of 2015, royalties as a percentage of revenue in the first quarter of 2016 decreased due to the sliding scale mechanism which results in lower royalties when commodity prices are low, coupled with the impact of wells that were drilled between late 2015 and first quarter 2016 which qualify for an initial lower royalty rate, partially offset by higher royalty rates from wells acquired in the Wilson Creek area of Alberta in September 2014 (the "Wilson Creek Acquisition") and the Alder Flats Acquisition in June 2015.

The Company expects royalty rates to remain similar in 2016 compared to 2015 due to continued forecast low commodity prices and the mix of new wells that qualify for the initial lower royalty rate of 5%.

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.

Production Expenses

	Three months ended March 31,		
	2016	2015	% change
Total production expenses	**$10,154,758**	$9,139,317	11
Total ($/boe)	**$11.65**	$12.55	(7)

Production expenses for the first quarter of 2016 decreased by 5% to $11.65/boe compared to $12.20/boe incurred during the fourth quarter of 2015. The $0.55/boe decrease in the first quarter of 2016 resulted from a combination of several factors, including the start-up of a new oil trucking terminal in Wilson Creek and an optimization debottlenecking project that was completed in Alder Flats in the first quarter of 2016. Also contributing to lower operating costs was the continuation of the Company-wide initiative to reduce service costs, plus the Company benefited from new production coming on-stream in the lower-cost Wilson Creek area. On an absolute basis, overall costs decreased in the first quarter of 2016 to $10,154,758 compared to $11,182,990 in the fourth quarter of 2015, due to the lower cost structure and the 4% decrease in production. Tamarack will continue to focus efforts on reducing operating costs throughout 2016 to improve overall netbacks.

First quarter 2016 production expenses were 7% lower than $12.55/boe realized in the same quarter of 2015, but increased 11% on an absolute basis to $10,154,758, compared to $9,139,317 for the same period in 2015. The lower production expenses on a per boe basis 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 an 18% increase in production and the facility rental arrangements, partially offset by lower per unit costs.

Production expenses are expected to continue improving both on an absolute and a per boe basis in the second quarter of 2016 following the installation of a field compressor which will divert Company production away from third party facilities into operated facilities. In addition, expenses will benefit from a full quarter impact of the new oil truck terminal in Wilson Creek and the debottlenecking infrastructure project in Alder Flats, both of which were completed late in the first quarter of 2016.

Operating Netback

($/boe)	Three months ended March 31, 2016	2015	% change
Average realized sales	**22.50**	34.75	(35)
Royalty expenses	**(2.04)**	(3.78)	(46)
Production expenses	**(11.65)**	(12.55)	(7)
Operating field netback	**8.81**	18.42	(52)
Realized commodity hedging gain (loss)	**7.23**	5.00	45
Operating netback	**16.04**	23.42	(32)

Operating netback for the first quarter of 2016 decreased by 31% to $16.04/boe compared to $23.39/boe during the fourth quarter of 2015. This is attributable to a 21% decrease in oil and natural gas liquids prices ($30.90/bbl versus $39.30/bbl), a 24% decrease in natural gas prices ($2.03/mcf versus $2.66/mcf) and a realized hedging gain of $7.23/boe in first quarter 2016 compared to $8.16/boe in the fourth quarter of 2015, partially offset by a 5% decrease in operating expense per boe ($11.65/boe versus $12.20/boe) and a 27% decrease in royalty expense per boe ($2.04/boe versus $2.80/boe).

The first quarter 2016 operating netback decreased by 32% compared to $23.42/boe in first quarter 2015. This was due to a 31% decrease in oil and natural gas liquids prices ($30.90/bbl versus $44.81/bbl) and a 30% decrease in natural gas prices ($2.03/mcf versus $2.91/mcf), partially offset by royalty expenses per boe that were 46% lower ($2.04/boe versus $3.78/boe), operating expenses that were 7% lower ($11.65/boe versus $12.55/boe) and higher realized hedging gains ($7.23/boe versus $5.00/boe).

General and Administrative Expenses

	Three months ended March 31, 2016	2015	% change
Gross costs	**$2,304,248**	$2,470,521	(7)
Capitalized costs and recoveries	**(533,562)**	(397,830)	34
General and administrative costs	**$1,770,686**	$2,072,691	(15)
Total ($/boe)	**$2.03**	$2.85	(29)

General and administrative expenses for the first quarter of 2016 were $2.03/boe on costs of $1,770,686 compared to $1.94/boe on costs of $1,780,474 in the fourth quarter of 2015. While overall costs remained similar quarter over quarter, the costs per unit increased by 5% in the first quarter of 2016 due to a 4% decrease in production.

During the first quarter of 2015, general and administrative expenses were $2.85/boe on costs of $2,072,691. The 29% decrease in the first quarter 2016 cost per boe was due to the impact of the 18% increase in production and 15% decrease in absolute general and administrative costs.

Stock-based Compensation Expenses

Stock-based compensation expenses relating to stock options and restricted share awards were $951,583 for the three months ended March 31, 2016, compared to $739,513 for the same period in 2015. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

The Company capitalized $406,774 of stock-based compensation expenses relating to exploration and development activities for the three months ended March 31, 2016, compared to capitalizing $413,392 for the same period in 2015.

Interest

Interest expense was $1,043,441 for the three months ended March 31, 2016, compared to $1,241,534 for the same period in 2015. The Company had $50,055,920 drawn on its revolving credit facility at March 31, 2016, compared to $112,951,205 drawn on its bank line at March 31, 2015. Interest expense was lower for the three months ended March 31, 2016 compared to the same time period in 2015 due to a lower average amount drawn quarter over quarter on the revolving credit facility. The average amount drawn through the first quarter in 2016 was approximately $74 million as compared to an average amount drawn of approximately $108 million in first quarter of 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 March 31,		
	2016	2015	% change
Depletion and depreciation	**$15,150,494**	$15,927,212	(5)
Amortization of undeveloped leases	**165,718**	204,927	(19)
Accretion	**346,802**	257,100	35
Total	**$15,663,014**	$16,389,239	(4)
Depletion and depreciation ($/boe)	**$17.38**	$21.87	(21)
Amortization ($/boe)	**0.19**	0.28	(32)
Accretion ($/boe)	**0.40**	0.35	14
Total ($/boe)	**$17.97**	$22.50	(20)

Depletion, depreciation, amortization, and accretion (“DDA&A”) expense on a boe basis for the first quarter of 2016 was 2% higher at $17.97/boe, compared to $17.62/boe during the fourth quarter of 2015. This modest increase was the result of an impairment reversal taken on the Company’s Heavy Oil CGU at the end of the fourth quarter of 2015. For the first quarter of 2016, DDA&A expense was $15,663,014 compared to $16,159,091 for the fourth quarter of 2015. The 3% decrease in total DDA&A expense quarter over quarter was the result of a 4% decrease in production partially offset by higher DDA&A expense on a boe basis.

First quarter 2016 DDA&A expense was $17.97/boe, compared to $22.50/boe for the same period in 2015, with the decrease due to a lower amortization rate, 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 4% lower in the first quarter of 2016 at $15,663,014, compared to $16,389,239 in the first quarter of 2015, due to lower per unit DDA&A expenses partially offset by the 18% increase in production.

Income Taxes

The Company did not incur any cash tax expense in the three months ended March 31, 2016, nor does it expect to pay any cash taxes in 2016 or in 2017 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three months ended March 31, 2016, a deferred income tax recovery of $1,806,024 was recognized, compared to a deferred income tax recovery expense of $1,500,705 for the same period in 2015. There was a deferred tax recovery during the three months ended December 31, 2015 and 2014 due to a loss before taxes.

Funds from Operations and Net Income

	Three months ended March 31,		
	2016	2015	% change
Petroleum and natural gas sales	**$19,618,659**	$25,310,633	(22)
Royalties	**(1,780,362)**	(2,756,164)	35
Realized gain (loss) on financial instruments	**6,305,002**	3,641,859	73
Production expenses	**(10,154,758)**	(9,139,317)	(11)
General and administration expenses	**(1,770,686)**	(2,072,691)	15
Transaction costs	**(96,254)**	–	–
Interest	**(1,043,441)**	(1,241,534)	16
Funds from operations	**$11,078,160**	$13,742,786	(19)

Funds from operations during the first quarter of 2016 were $11,078,160 ($0.11 per share basic and diluted) compared to $18,614,626 ($0.19 per share basic and diluted) for the fourth quarter of 2015. The decrease is primarily the result of a 21% decrease in crude oil and natural gas liquids pricing and a 24% decrease in the natural gas price, a 4% decrease in production and a lower realized hedging gain, partially offset by a 9% decrease in production expenses and a 31% decrease in royalty expense.

Compared to funds from operations of $13,742,786 ($0.18 per share basic and diluted) in the same period in 2015, first quarter 2016 funds from operations were 19% lower as a result of a 31% decrease in crude oil and natural gas liquids pricing, a 30% decrease in natural gas pricing and higher production expenses related to Tamarack's increased volumes, partially offset by a higher realized hedging gain in the first quarter of 2016 compared to the same period in 2015, an 18% increase in production and lower royalty expenses.

($/boe)	Three months ended March 31, 2016	2015	% change
Petroleum and natural gas sales	**$22.50**	$34.75	(35)
Royalties	**(2.04)**	(3.78)	46
Realized gain (loss) on financial instruments	**7.23**	5.00	45
Production expenses	**(11.65)**	(12.55)	7
General and administration expenses	**(2.03)**	(2.85)	29
Transaction costs	**(0.11)**	–	–
Interest	**(1.20)**	(1.70)	30
Funds from operations	**12.71**	18.87	(33)

First quarter 2016 funds from operations decreased to $12.71/boe from $20.30/boe in the fourth quarter of 2015 due to an 11% decrease in the realized hedging gain, 21% and 24% decreases in crude oil and natural gas liquids prices and natural gas prices, respectively, partially offset by a 4% decrease in production expenses per boe and a 27% decrease in royalty expense per boe.

The Company had a net loss of $5,834,537 ($0.06 per share basic and diluted) during the three months ended March 31, 2016, compared to net income of $5,118,919 ($0.05 per share basic and diluted) for the fourth quarter of 2015. The Company recorded a net loss for the three months ended March 31, 2016 as compared to a profit in the fourth quarter of 2015 as a result of a recovery to property, plant and equipment in the fourth quarter 2015, an unrealized gain on financial instruments taken in the fourth quarter of 2015, a 21% decrease in crude oil and natural gas liquids pricing and a 24% decrease in natural gas pricing.

The Company had a net loss of $5,834,537 ($0.06 per share basic and diluted) during the three months ended March 31, 2016, compared to a net loss of $5,241,630 ($0.07 per share basic and diluted) for the same period in 2015. This was a result of several factors, including a 31% decrease in crude oil and natural gas liquids pricing, a 30% decrease in natural gas pricing and higher production expenses related to increased production, partially offset by higher realized hedging gains in the first quarter of 2016 compared to the first quarter of 2015 and an 18% 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 March 31, 2016	2015	% change
Land	**609,237**	$75,622	706
Geological and geophysical	**411,639**	30,506	1,249
Drilling and completion	**14,245,899**	4,608,729	209
Equipment and facilities	**1,532,552**	1,966,669	(22)
Capitalized G&A	**235,514**	167,231	41
Office equipment	**114,497**	–	–
Total capital expenditures	**$17,149,338**	$6,848,757	150
Proceeds from disposal of property, plant and equipment	**–**	(1,820,583)	(100)
Total net capital expenditures	**$17,149,338**	$5,028,174	241

During the first quarter of 2016, the Company finished drilling, completed and equipped 2 (1.70 net) previously spudded horizontal Cardium oil wells all in the Wilson Creek/Alder Flats area. The Company also drilled, completed and equipped 3 (2.50 net) Cardium oil wells, 1 (0.78 net) Mannville gas well all in the Wilson Creek/Alder Flats area and 1.0 net Heavy oil well. The Company completed debottlenecking infrastructure in the recently acquired Alder Flats area in order to optimize operations by increasing capacity and reducing operating costs.

2016 Drilling Summary (including wells spudded by March 31, 2016)		
	Gross	Net
Heavy Oil	1.0	1.0
Mannville	1.0	0.8
Cardium	3.0	2.5
	5.0	4.3

The Company has also been focused on adding drilling inventory through minor tuck-in land acquisitions in its core areas. During the first quarter, ten minor deals were completed that added approximately 10.5 net sections of undeveloped land.

The Company's net undeveloped land was 218,521 acres at the end of the first quarter of 2016.

Liquidity and Capital Resources

Tamarack's net debt, including working capital deficiency excluding the fair value of financial instruments, was $62,696,456 at March 31, 2016. Tamarack's net debt at March 31, 2015 was $121,159,015 and at December 31, 2015 was $97,940,880. During the three months ended March 31, 2016 the Company reduced net debt by $35,244,424 through an equity issuance described below, which improved financial flexibility. Tamarack's March 31, 2016 net debt to annualized funds from operations was consistent with yearend December 31, 2015 at 1.4 times.

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

At March 31, 2016 and May 10, 2016, there were 114,937,425 common shares, 1,110,584 preferred shares, 4,668,884 options and 1,861,167 restricted share awards outstanding. This compares to December 31, 2015 at which time there were 99,971,325 common shares, 1,110,584 preferred shares, 4,668,884 options and 1,861,167 restricted share awards outstanding. The Company had 102,273,802 weighted average basic common shares outstanding during the three months ended March 31, 2016.

At March 31, 2016, the Company had a revolving credit facility in the amount of $155,000,000 and a $10,000,000 operating facility (collectively the "Facility"). The Facility lasts for a 364 day period and will be subject to its next 364 day extension by May 27, 2016. If not extended, the Facility will cease to revolve and all outstanding balances will become repayable one year from that extension date being May 27, 2017. 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 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 scheduled review is expected to conclude by May 27, 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 credit facilities 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 of 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, was 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 preserve capital efficiencies.

2016 Guidance

Tamarack's 2016 capital program and associated guidance was designed with the key priority of maintaining a strong and flexible balance sheet. The capital program and guidance released on January 19, 2016, was based on a 2016 WTI average of $40.00/bbl USD and an AECO average of $2.45/GJ with a plan to adjust capital spending as commodity prices changed. Despite having a high-quality drilling inventory that achieves 1.5 year payouts or less in the current pricing environment, the Company adjusted capital spending as a result of the continued volatility in commodity prices. The top priority is to maintain a strong balance sheet in order to continue its successful pursuit of tuck-in acquisitions within its core areas and continuing to add high quality drilling inventory. In addition, the Company has deferred approximately $6 to $8 million of capital into the second half of 2016. Tamarack will continue to closely monitor the broader commodity price environment and has the flexibility to further reduce capital expenditures if commodity prices do not improve further from current levels.

2016 Assumptions:

- WTI average $33.00/bbl to 40.00/bbl USD.
- Edmonton par price average $41.00/bbl to 51.45/bbl.
- AECO average $2.00/GJ to 2.45/GJ.
- Canadian/US dollar exchange rate range of $0.70 to $0.72.

2016 Guidance Ranges:

- Capital expenditures of $40-57 million.
- Average production of 8,700-9,700 boe/d (approximately 51-57% oil & NGLs).
- Exit production of 8,600-9,800 boe/d (approximately 50-55% oil & NGLs).
- Estimated 2016 year end 12-month trailing debt to cash flow (including hedges) ratio between 0.9 and 1.4 times.

Commitments

The following table summarizes the Company's commitments at March 31, 2016:

	2016	2017	2018	2019	2020	2021	2022	2023
Office lease	498,784	641,312	541,718	541,718	262,535	–	–	–
Take or pay commitments (1)	741,150	985,500	985,500	–	–	–	–	–
Drilling commitments (2)	2,609,000	–	–	–	–	–	–	–
Rental fee (3)	3,877,594	5,170,125	5,170,125	5,170,125	5,170,125	5,170,125	3,299,093	714,000
Total	7,726,528	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 34 months.

(2) Drilling and completion commitments related to the farm-in entered into on August 19, 2013. Overall 15 net wells had to be drilled by December 31, 2016. In the event the Company gets access to certain lands, that are currently restricted from access due to regulatory conditions, the number of wells would then increase to 20 and the Company would have until December 31, 2017 to fulfill this commitment. As of March 31, 2016, the Company had satisfied approximately 70% to 93% of the drilling commitment and estimates the capital expenditures to fulfill the remainder of this commitment will be between $3 and $15 million, depending on how many wells are required to be drilled.

(3) 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 generated 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 its 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 March 31,	
	2016	2015
Cash provided by operating activities	**$14,482,803**	$16,871,206
Abandonment expenditures	**153,197**	66,554
Changes in non-cash working capital	**(3,557,840)**	(3,194,974)
Funds from operations	**$11,078,160**	$13,742,786
Funds from operation per share -basic	**$ 0.11**	$ 0.18
Funds from operation per share -diluted	**$ 0.11**	$ 0.18

(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 6 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):

	March 31, 2016	December 31, 2015
Cash and cash equivalents	**$ –**	$ –
Accounts receivables	**14,942,016**	15,571,507
Prepaid expenses	**1,073,914**	1,039,634
Accounts payable and accrued liabilities	**(28,656,466)**	(31,730,161)
Bank debt	**(50,055,920)**	(82,821,860)
Net debt	**$ (62,696,456)**	$ (97,940,880)

Selected Quarterly Information

Three months ended	**Mar. 31, 2016**	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2014	Sep. 30, 2014	Jun. 30, 2014
Sales volumes								
Natural gas *(mcf/d)*	**25,818**	23,229	22,005	16,972	17,864	17,518	12,462	12,033
Oil and NGL's *(bbls/d)*	**5,279**	6,096	5,049	4,163	5,115	4,761	3,688	3,197
Average boe/d *(6:1)*	**9,582**	9,968	8,717	6,992	8,092	7,681	5,765	5,203
Product prices								
Natural gas *($/mcf)*	**2.03**	2.66	3.04	2.80	2.91	3.91	4.13	4.37
Oil and NGL's *($/bbl)*	**30.90**	39.30	46.56	55.47	48.33	62.87	90.19	94.65
Oil equivalent *($/boe)*	**22.50**	30.23	34.64	39.82	34.75	47.89	66.62	68.27
(000s, except per share amounts)								
Financial results								
Gross revenues	**19,619**	27,725	27,779	25,331	25,311	33,839	35,333	32,322
Funds from operations	**11,078**	18,615	14,618	13,186	13,743	19,128	15,809	17,790
Per share – basic	**0.11**	0.19	0.15	0.16	0.18	0.25	0.26	0.29
Per share – diluted	**0.11**	0.18	0.15	0.16	0.18	0.25	0.26	0.29
Net income (loss)	**(5,835)**	5,119	(15,064)	(2,142)	(5,242)	(38,991)	6,791	5,243
Per share – basic	**(0.06)**	0.05	(0.15)	(0.03)	(0.07)	(0.50)	0.11	0.09
Per share – diluted	**(0.06)**	0.05	(0.15)	(0.03)	(0.07)	(0.50)	0.11	0.08
Additions to property and equipment, net of proceeds	**17,149**	8,743	21,936	14,246	5,028	26,774	30,318	40,742
Net property acquisitions	**–**	2,075	1,230	54,174	–	–	166,057	–
Total assets	**553,135**	549,068	549,652	561,977	482,227	497,578	525,003	319,065
Working capital (deficiency)(1)	**(62,696)**	(97,941)	(105,837)	(97,280)	(121,159)	(129,799)	(121,684)	(59,490)
Bank debt(2)	**50,056**	82,822	94,423	88,500	112,951	100,200	100,275	43,735
Decommissioning obligations	**65,643**	63,331	61,808	64,883	45,340	41,357	36,732	20,956
Deferred income tax (asset)	**(38,576)**	(36,168)	(35,770)	(33,647)	(28,802)	(27,299)	(16,870)	(17,743)

(1) Excluding fair value of financial instruments
(2) The debt Facility was previously demand and included in the working capital deficiency

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 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.
- On June 15, 2015, the Company acquired certain working interests in developed petroleum and natural gas properties in the Alder Flats area of Alberta; in 2015 this acquisition added $7,266,186 to oil and natural gas revenue and contributed $1,045,845 to net loss.
- 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; in 2014 this acquisition added $5,551,131 to oil and natural gas revenue and contributed $402,656 to net income.
- The Company recorded $1,044,308 in transaction costs in the second and third quarters of 2015 related the 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 this period 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 completing 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:

- Estimated production rates in 2016.
- Accelerations to the capital spending to account for strengthened commodity prices.
- Future operating costs on a per boe basis.
- Reduction of production expenses on an absolute and per boe basis in the second quarter of 2016.
- Tamarack's focus on reducing capital and operating costs.
- Tamarack's primary focus areas for production growth.
- Future drilling plans.
- Deferred tax liabilities.
- The interest rates under, and 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 due to commodity price volatility.

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;
- 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;
- the realization of anticipated benefits of acquisitions, including 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 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.

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.

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)

	March 31, 2016	December 31, 2015
Assets		
Current assets:		
Accounts receivable	$14,942,016	$15,571,507
Prepaid expenses and deposits	1,073,914	1,039,634
Fair value of financial instruments (note 3)	10,363,977	12,468,101
	26,379,907	29,079,242
Property, plant and equipment (note 4)	484,972,773	481,615,900
Exploration and evaluation assets (note 5)	3,206,155	2,204,978
Deferred tax asset	38,576,316	36,167,594
	$553,135,151	$549,067,714
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$28,656,466	$31,730,161
Bank debt (note 10)	50,055,920	82,821,860
Decommissioning obligations (note 6)	65,642,605	63,330,850
Shareholders' equity:		
Share capital (note 8)	458,146,855	416,075,358
Contributed surplus	18,402,761	17,044,404
Deficit	(67,769,456)	(61,934,919)
	408,780,160	371,184,843
Commitments and contingencies (note 12)		
	$553,135,151	$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 months ended March 31, 2016 and 2015
(unaudited)

	2016	2015
Revenue:		
Oil and natural gas	$19,618,659	$25,310,633
Royalties	(1,780,362)	(2,756,164)
Realized gain on financial instruments (note 3)	6,305,002	3,641,859
Unrealized loss on financial instruments (note 3)	(2,104,124)	(2,809,281)
	22,039,175	23,387,047
Expenses:		
Production	10,154,758	9,139,317
General and administration	1,770,686	2,072,691
Transaction costs	96,254	–
Stock-based compensation (note 11)	951,583	739,513
Finance	1,390,243	1,498,634
Depletion, depreciation and amortization	15,316,212	16,132,139
Loss on disposition of property, plant and equipment	–	547,088
	29,679,736	30,129,382
Loss before taxes	(7,640,561)	(6,742,335)
Deferred income tax recovery	1,806,024	1,500,705
Net loss and comprehensive loss	$(5,834,537)	$(5,241,630)
Net loss per share (note 9):		
Basic	$(0.06)	$(0.07)
Diluted	$(0.06)	$(0.07)

See accompanying notes to the condensed consolidated interim financial statements.

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	14,966,100	43,701,012	–	–	43,701,012
Share issue costs, net of tax of $602,698	–	(1,629,515)	–	–	(1,629,515)
Stock-based compensation	–	–	1,358,357	–	1,358,357
Net loss	–	–	–	(5,834,537)	(5,834,537)
Balance at March 31, 2016	114,937,425	$458,146,855	$18,402,761	$(67,769,456)	$408,780,160

	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
Share issue costs, net of tax of $2,100	–	(6,300)	–	–	(6,300)
Stock-based compensation	–	–	1,152,905	–	1,152,905
Net loss	–	–	–	(5,241,630)	(5,241,630)
Balance at March 31, 2015	77,928,466	$336,080,362	$14,084,263	$(49,848,181)	$300,316,444

See accompanying note to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three months ended March 31, 2016 and 2015
(unaudited)

	2016	2015
Cash provided by (used in):		
Operating:		
Net loss	$(5,834,537)	$(5,241,630)
Items not involving cash:		
Depletion, depreciation and amortization	15,316,212	16,132,139
Stock-based compensation	951,583	739,513
Loss on disposition of property, plant and equipment	–	547,088
Accretion expense on decommissioning obligations	346,802	257,100
Unrealized loss on financial instruments	2,104,124	2,809,281
Deferred income tax recovery	(1,806,024)	(1,500,705)
Funds from operations	11,078,160	13,742,786
Abandonment expenditures (note 6)	(153,197)	(66,554)
Changes in non-cash working capital (note 7)	3,557,840	3,194,974
Cash provided by operating activities	14,482,803	16,871,206
Financing:		
Change in bank debt	(32,765,940)	12,751,205
Proceeds from issuance of shares	43,701,012	–
Share issue costs	(2,232,213)	(8,400)
Cash provided by financing activities	8,702,859	12,742,805
Investing:		
Property, plant and equipment additions	(16,042,019)	(6,477,690)
Exploration and evaluation additions	(1,107,319)	(371,067)
Proceeds from disposal of property, plant and equipment	–	1,820,583
Changes in non-cash working capital (note 7)	(6,036,324)	(25,415,941)
Cash used in investing activities	(23,185,662)	(30,444,115)
Change in cash and cash equivalents	–	(830,104)
Cash and cash equivalents, beginning of period	–	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 incorporated under the *Business Corporations Act* (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 3100, 250 – 6th Avenue S.W., Calgary, Alberta T2P 3H7.

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 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 May 10, 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 sale 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 future value to profit and loss and therefore carrying amount equals future value.

At March 31, 2016, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value (Cdn $)
Crude oil	2,400 bbls/day	April 1, 2016 – June 30, 2016	WTI fixed price	Cdn $76.21	$5,332,651
Crude oil	1,800 bbls/day	July 1, 2016 – September 30, 2016	WTI fixed price	Cdn $69.92	$2,545,798
Crude oil	1,700 bbls/day	October 1, 2016 – December 31, 2016	WTI fixed price	Cdn $66.66	$1,678,033
Crude oil	900 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $56.99	$6,841
Crude oil	900 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $58.17	$29,291
Natural gas	3,000 GJ/day	April 1, 2016 – October 31, 2016	AECO fixed price	Cdn $2.53	$732,511
Natural gas	4,000 GJ/day	October 1, 2016 – December 31, 2016	AECO fixed price	Cdn $2.29	$35,512
Natural gas	6,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.61	$3,340
					$10,363,977

At March 31, 2016, the commodity contracts were fair valued with an asset of $10,363,977 (December 31, 2015 - $12,468,101) recorded on the balance sheet and an unrealized loss of $2,104,124 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 March 31, 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	April 1, 2016 – June 30, 2016	AECO fixed price	Cdn $2.40
Natural gas	2,000 GJ/day	July 1, 2016 – August 31, 2016	AECO fixed price	Cdn $2.44

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	**March 31, 2016**	December 31, 2015
Risk management contracts		
Current asset	**$10,363,977**	$12,468,101
Current liability	–	–
Balance, end of the period	**$10,363,977**	$12,468,101

Since March 31, 2016, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	600 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $61.12
Crude oil	400 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $61.53
Crude oil	200 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $62.00
Natural gas	3,000 GJ/day	October 1, 2016 – December 31, 2016	AECO fixed price	Cdn $2.25
Natural gas	2,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.55
Natural gas	10,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.34
Natural gas	7,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.37

Since March 31, 2016, the Company has entered into the following physical commodity contracts:

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

4. 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
Cash additions	15,927,522	114,497	16,042,019
Decommissioning costs	2,118,150	–	2,118,150
Stock-based compensation	406,774	–	406,774
Transfer from exploration and evaluation assets	(59,576)	–	(59,576)
Balance at March 31, 2016	$734,780,914	$715,728	$735,496,642
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	15,120,992	29,502	15,150,494
Balance at March 31, 2016	$250,229,690	$294,179	$250,523,869

	Oil and Natural Gas Interests	Other Assets	Total
Carrying amounts:			
At December 31, 2015	$481,279,346	$336,554	$481,615,900
At March 31, 2016	$484,551,224	$421,549	$484,972,773

The calculation of depletion at March 31, 2016 includes estimated future development costs of $350,112,000 (December 31, 2015 – $361,667,000) associated with the development of the Company’s proved plus probable reserves and excludes salvage value of $26,138,000 (December 31, 2015 – $25,630,400).

5. 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	1,107,319
Transfer to property, plant and equipment	59,576
Balance at March 31, 2016	$23,249,743
Amortization and impairment:	
Balance at January 1, 2015	$19,162,226
Amortization	715,644
Balance at December 31, 2015	19,877,870
Amortization	165,718
Balance at March 31, 2016	$ 20,043,588

	Total
Carrying amounts:	
At December 31, 2015	$2,204,978
At March 31, 2016	$3,206,155

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.

6. 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 $63.5 million at March 31, 2016 (December 31, 2015 – $63.0 million), which is expected to be incurred between 2016 and 2038. A risk-free rate of 2.0% (2015 – 2.2%) and an inflation rate of 2% (2015 – 2%) is used to calculate the fair value of the decommissioning obligations at March 31, 2016 as presented in the table below:

	March 31, 2016	December 31, 2015
Balance, beginning of the period	**$63,330,850**	$41,356,532
Liabilities incurred	**452,553**	1,091,390
Liabilities acquired	–	9,237,544
Change in estimates	**1,665,597**	444,130
Change in discount rate on acquisition	–	10,671,976
Expenditures	**(153,197)**	(155,559)
Liabilities disposed	–	(369,117)
Accretion	**346,802**	1,053,954
Balance, end of the period	**$65,642,605**	$63,330,850

A change in estimates for 2016 resulted from the decommissioning obligations being revalued using the risk-free rate of 2.0% as opposed to the risk free rate of 2.2% used in 2015.

7. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	2016	2015
Source/(use of cash):		
Accounts receivable	**$629,491**	$5,600,968
Prepaid expenses and deposits	**(34,280)**	169,796
Accounts payable and accrued liabilities	**(3,073,695)**	(27,991,731)
	$(2,478,484)	$(22,220,967)
Related to operating activities	**$3,557,840**	$3,194,974
Related to investing activities	**(6,036,324)**	(25,415,941)

8. Share capital:

At March 31, 2016 the Company was authorized to issue an unlimited number of common shares and preferred shares without nominal or par value.

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 being exercised for 1,952,100 Common Shares. Certain officers, directors and employees acquired 281,335 common shares for gross proceeds of $821,498.

9. Income (loss) per share:

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

	2016	2015
Net loss	**$(5,834,537)**	$(5,241,630)
Weighted average shares - basic	**102,273,802**	77,928,466
Weighted average shares - diluted	**102,273,802**	77,928,466
Net loss per share-basic	**$(0.06)**	$(0.07)
Net loss per share-diluted	**$(0.06)**	$(0.07)

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three months ended March 31, 2016, 7,640,635 stock options, preferred shares and restrictive stock units, respectively, were excluded from the diluted earnings per share as they were anti-dilutive. For the three months ended March 31, 2015, 5,595,218 stock options, preferred shares and restrictive stock units, respectively, were excluded from the diluted earnings per share as they were anti-dilutive.

10. Bank debt:

At March 31, 2016, the Company had a revolving credit facility in the amount of $155 million and a $10 million operating facility (collectively the “Facility”). The Facility lasts for a 364 day period and will be subject to its next 364 day scheduled review and extension by May 27, 2016. If not extended, the Facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date being May 27, 2017. 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 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 scheduled review is to take place during the second quarter of 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 March 31, 2016, the Company had utilized the Facility in the amount of $50.1 million and the Company was compliant with its working capital ratio at 4.6 to 1.0.

As at March 31, 2016, the Company had letters of guarantee outstanding in the amount of $43,980 against the Facility.

11. Share-based payments:

(a) Preferred share plan:

The Company has 1,110,584 preferred shares (December 31, 2015 – 1,110,584) outstanding and fully vested at March 31, 2016. The preferred shares 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 11,493,743 options or restricted share units to its employees, directors and consultants of which 7,122,781 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 and March 31, 2016	4,668,884	$ 3.59

The following table summarizes information about stock options outstanding and exercisable at March 31, 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	1,753,051	$2.35	2.7	1,025,829	$2.10
$ 3.01 – 5.00	2,449,833	$3.85	2.5	1,623,832	$3.85
$ 5.01 – 6.82	466,000	$6.82	3.4	155,333	$6.82
$ 1.86 – 6.82	**4,668,884**	**$3.59**	**2.7**	**2,804,994**	**$3.38**

(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 restrictive 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 and March 31, 2016	1,861,167

12. Commitments and contingencies:

(a) Commitments

The following table summarizes the Company's commitments at March 31, 2016:

	2016	2017	2018	2019	2020	2021	2022	2023
Office lease	498,784	641,312	541,718	541,718	262,535	–	–	–
Take or pay commitments(1)	741,150	985,500	985,500	–	–	–	–	–
Drilling commitments(2)	2,609,000	–	–	–	–	–	–	–
Rental fee(3)	3,877,594	5,170,125	5,170,125	5,170,125	5,170,125	5,170,125	3,299,093	714,000
Total	7,726,528	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 34 months.

(2) Drilling and completion commitments related to the farm-in entered into on August 19, 2013. Overall 15 net wells needed to be drilled by December 31, 2016. In the event the Company gets access to certain lands, that are currently restricted from access due to regulatory conditions, the number of wells would then increase to 20 and the Company would have until December 31, 2017 to fulfill this commitment. As of March 31, 2016, the Company had satisfied approximately 70% to 93% of the drilling commitment and estimates the capital expenditures to fulfill the remainder of this commitment will be between $3 and $15 million, depending on how many wells are required to be drilled.

(3) 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.

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

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

Lead Bank Syndicate

National Bank of Canada

Legal Counsel

Osler, Hoskin & Harcourt LLP

Auditor

KPMG LLP

Stock Exchange

Toronto Stock Exchange
Stock symbol: TVE

Contact Information

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