MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the years ended December 31, 2016 and 2015. This MD&A is dated and based on information available on March 22, 2017 and should be read in conjunction with the audited consolidated financial statements and notes for the years ended December 31, 2016 and 2015. Additional information relating to Tamarack, including Tamarack's annual information form, is available on SEDAR at www.sedar.com.

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

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

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 Year Ended December 31, 2016

During the year ended December 31, 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. 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 dates 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 January 11, 2017, Tamarack closed the previously announced 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 held Spur's Viking oil assets at closing (the "Viking Acquisition"). Under the terms of the Arrangement Agreement, the Company issued an aggregate of 90.1 million common shares of Tamarack and paid $57.3 million in cash. Tamarack also assumed Spur's net debt, estimated to be $25.7 million as at January 11, 2017, after accounting for proceeds from the exercise of all outstanding options of Spur, as well as severance and transaction costs. Based upon Tamarack's share price on January 11, 2017 of $3.44 per share, the total consideration paid by Tamarack, including the assumption of debt, was approximately $393 million. After giving effect to the Viking Acquisition at December 31, 2016, the Company estimates that its net debt would have been approximately $128 million.

As a result of the Viking Acquisition, Tamarack is repositioned as an intermediate oil-weighted Cardium and Viking-focused growth company with production of approximately 18,000 boe/d (56% light oil and NGLs) and over 800 net total identified drilling 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 less than 1.0 times, and no immediate requirement for equity to fund development of the combined assets in 2017.

Production

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Production						
Light oil (bbls/d)	**4,858**	4,258	14	**4,215**	3,703	14
Heavy oil (bbls/d)	**316**	620	(49)	**363**	602	(40)
Natural gas liquids (bbls/d)	**1,075**	1,218	(12)	**1,035**	803	29
Natural gas (mcf/d)	**31,226**	23,229	34	**28,388**	20,038	42
Total (boe/d)	**11,453**	9,968	15	**10,344**	8,448	22
Percentage of oil and natural gas liquids	**55%**	61%		**54%**	60%	

Tamarack achieved strong production results for the year ended December 31, 2016, averaging 10,344 boe/d. Better than expected capital efficiencies and higher than expected production results from a successful 2016 drilling program and from the Penny and Redwater Acquisition contributed to volumes that 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 of 2016 due to TransCanada pipeline curtailments.

Annual volumes in 2016 were 22% higher than the 8,448 boe/d produced during the same period in 2015, reflecting the impact of a full year of production from certain working interests acquired in the producing Alder Flats area of Alberta in mid-2015 (the "Wilson Creek / Alder Flats Acquisition") as well as the impact of nearly two full quarters of production from assets acquired in the Penny and Redwater Acquisitions, partially offset by expected declines from existing production.

Average production for the fourth quarter of 2016 increased by 6% to 11,453 boe/d from 10,790 boe/d in the third quarter of 2016, and was 15% higher than 9,968 boe/d in the fourth quarter of 2015. Fourth quarter volumes were positively impacted by a combined average of 878 boe/d attributable to a full quarter of production from the Penny and Redwater Acquisitions, and volume additions from one (1.0 net) Cardium oil wells and one (1.0 net) oil well in the Penny area that were brought on stream during the fourth quarter, partially offset by expected declines from existing production.

Crude oil and natural gas liquids production in the fourth quarter of 2016 averaged 6,249 bbls/d, an increase of 5% compared to the third quarter of 2016 production of 5,955 bbls/d. A combined average of 597 bbls/d were added due to a full quarter of production from the Penny and Redwater Acquisitions, and volume additions from one (1.0 net) Cardium oil well and one (1.0 net) oil well in the Penny area that were brought on stream during the fourth quarter.

Tamarack's oil and natural gas liquids represented 55% of total production in both the third and fourth quarters of 2016. For 2017, the Company expects its oil and natural gas liquids weighting to fluctuate between 55% and 62% depending on the timing of production additions from its higher oil-weighted areas of Wilson Creek, Redwater, Penny and assets from the Viking Acquisition, compared to additions coming from the higher natural gas-weighted area of Alder Flats. 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 31,226 mcf/d in the fourth quarter of 2016, an increase of 8% over the 29,007 mcf/d produced in the prior quarter. The increase was primarily due to a reduction of TCPL curtailments and to a full quarter of production from the Penny and Redwater Acquisitions, which added a combined 1,686 mcf/d to the period’s production average.

Petroleum, Natural Gas Sales and Royalties

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Revenue						
Oil and NGLs	**$30,403,954**	$22,041,711	38	**$90,517,702**	$85,308,952	6
Natural gas	**9,389,261**	5,683,517	65	**24,999,247**	20,836,771	20
Total	**$39,793,215**	$27,725,228	44	**$115,516,949**	$106,145,723	9
Average realized prices:						
Light oil ($/bbl)	**58.71**	47.16	24	**50.53**	52.06	(3)
Heavy oil ($/bbl)	**44.60**	26.79	66	**35.45**	41.98	(16)
Natural gas liquids ($/bbl)	**28.99**	18.22	59	**20.74**	19.49	6
Combined average oil and NGLs ($/boe)	**52.88**	39.30	35	**44.06**	45.76	(4)
Natural gas ($/mcf)	**3.27**	2.66	23	**2.41**	2.85	(15)
Revenue $/boe	**37.76**	30.23	25	**30.51**	34.43	(11)
Benchmark pricing:						
Edmonton Par (Cdn$/bbl)	**60.76**	51.98	17	**51.76**	56.91	(9)
Hardisty Heavy (Cdn$/bbl)	**45.76**	37.04	24	**38.22**	45.54	(16)
AECO daily index (Cdn$/mcf)	**3.08**	2.47	25	**2.15**	2.69	(20)
AECO monthly index (Cdn$/mcf)	**2.80**	2.64	6	**2.08**	2.75	(24)
Royalty expenses	**$3,745,935**	$2,564,759	46	**$8,795,132**	$10,565,532	(17)
$/boe	**3.56**	2.80	27	**2.32**	3.43	(32)
percent of sales	**9**	9	–	**8**	10	(20)

Revenue from crude oil, natural gas and associated natural gas liquids sales was $39,793,215 in the fourth quarter of 2016, which was 26% higher than the $31,588,087 generated in the third quarter of 2016 and 44% higher than the $27,725,228 generated in the fourth quarter of 2015. The 26% increase in fourth quarter 2016 revenue over the previous quarter is attributable to natural gas prices that were 29% higher, crude oil and natural gas liquids prices that were 17% higher, a 5% increase in crude oil and natural gas liquids production and an 8% increase in natural gas production.

Revenue in the fourth quarter of 2016 increased 44% relative to the same period in 2015 primarily due to a 15% increase in production volumes, crude oil and natural gas liquids prices that were 35% higher and 23% higher natural gas prices.

Revenue during the year ended December 31, 2016 increased 9% to $115,516,949 compared to $106,145,723 in the same period in 2015 despite a 4% decrease in crude oil and natural gas liquids pricing and a 15% decrease in natural gas prices. The net increase was due to a 22% increase in production volumes.

Tamarack's realized prices for natural gas and the combined oil and natural gas liquids averaged $3.27/mcf and $52.88/bbl in the fourth quarter of 2016, respectively, compared to $2.54/mcf and $45.29/bbl in the third quarter of 2016 and $2.66/mcf and $39.30/bbl in the fourth quarter of 2015.

The realized crude oil prices for the three months and years ended December 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. The pentane plus and butane components within natural gas liquids price, increased in the fourth quarter and year ended December 31, 2016 by a greater margin than the Edmonton Par price due to improved supply and demand conditions in North America. Propane prices also improved in the fourth quarter of 2016 due to inventory levels in North America returning to more normal levels supported by better supply and demand conditions.. The Company expects that natural gas liquids prices in 2017 will generally correlate to the posted Edmonton Par price..

The Company's realized heavy oil price for the fourth quarter of 2016 increased by a greater margin than the Hardisty Heavy price due to tightening differentials, while realized heavy oil prices for the years ended December 31, 2016 and 2015 generally correlate to the Hardisty Heavy price for the same periods.

For the three months and years ended December 31, 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 December 31, 2016, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
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	1,200 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $65.05
Crude oil	1,200 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $70.13
Natural gas	16,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.77
Natural gas	18,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.51
Natural gas	18,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.54
Natural gas	9,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $2.79

At December 31, 2016, the commodity contracts were fair valued with a liability of $10,703,767 (December 31, 2015 – fair valued as an asset of $12,468,101) recorded on the balance sheet and an unrealized loss of $23,171,868 recorded in the net loss for the year ended December 31, 2016.

At December 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	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.55

Since December 31, 2016, the Company has entered into or assumed through the Viking Acquisition the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	800 bbls/day	January 1, 2017 – March 31, 2017	WTI fixed price	Cdn $70.21
Crude oil	800 bbls/day	April 1, 2017 – June 30, 2017	WTI fixed price	Cdn $70.14
Crude oil	1,100 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	Cdn $72.05
Crude oil	400 bbls/day	July 1, 2017 – September 30, 2017	WTI fixed price	US $55.23
Crude oil	800 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	Cdn $71.88
Crude oil	600 bbls/day	October 1, 2017 – December 31, 2017	WTI fixed price	US $55.08
Crude oil	200 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	Cdn $73.50
Crude oil	600 bbls/day	January 1, 2018 – March 31, 2018	WTI fixed price	US $55.07
Natural gas	5,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $3.35
Natural gas	5,000 GJ/day	April 1, 2017 – June 30, 2017	AECO fixed price	Cdn $2.95
Natural gas	5,000 GJ/day	July 1, 2017 – September 30, 2017	AECO fixed price	Cdn $2.95
Natural gas	5,000 GJ/day	October 1, 2017 – December 31, 2017	AECO fixed price	Cdn $3.04
Natural gas	2,000 GJ/day	January 1, 2018 – March 31, 2018	AECO fixed price	Cdn $3.14

Royalty expenses for the fourth quarter of 2016 were $3.56/boe or $3,745,935, representing 9% of revenue, compared to $2.24/boe or $2,219,838 for the third quarter of 2016, representing 7% of revenue. The $1.32/boe increase in royalties in the fourth quarter of 2016 compared to the third quarter of 2016 was related to the sliding scale mechanism which results in higher royalties when commodity prices are higher.

Royalties as a percentage of revenue were similar in the fourth quarter of 2016 compared to the fourth quarter of 2015, when royalty expenses were $2.80/boe or $2,564,759, representing 9% of revenue.

The royalty expense for the year ended December 31, 2016 was $2.32/boe or $8,795,132, representing 8% of revenue, compared to $3.43/boe or $10,565,532, representing 10% of revenue for the same period in 2015. The decrease in royalties as a percentage of revenue for the year ended December 31, 2016 relative to 2015 is due to the sliding scale mechanism which results in lower royalties when commodity prices decline, lower initial royalty rates on wells that were drilled between late 2015 and during 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.

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 took 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 December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Total production expenses	**$12,826,236**	$11,182,990	15	**$44,067,395**	$39,496,609	12
Total ($/boe)	**$12.17**	$12.20	(0)	**$11.64**	$12.81	(9)

Production expenses for the fourth quarter of 2016 increased by 5% to $12.17/boe compared to $11.58/boe incurred during the third quarter of 2016. The operating costs on a per boe basis increased as a result of the Penny Acquisition which feature higher per unit operating costs than Tamarack realizes in its other areas. On an absolute basis, overall costs increased in the fourth quarter of 2016 to $12,826,236 compared to $11,493,859 in the third quarter of 2016. The increase in total production costs resulted from a 6% increase in production and the increase in per unit costs.

On a per unit basis, fourth quarter 2016 production expenses were similar to the $12.20/boe realized in the same quarter of 2015, but increased 15% on an absolute basis to $12,826,236, compared to $11,182,990 for the same period in 2015, matching the increase in production volumes during the same period.

Production expenses for the year ended December 31, 2016 were 9% lower at $11.64/boe compared to $12.81/boe during the same period in 2015, but increased 12% on an absolute basis to $44,067,395, compared to $39,496,609 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. These cost reductions were partially offset by the Penny and Redwater Acquisitions which feature higher per unit operating costs than Tamarack realizes in its other areas. On an absolute basis, overall costs increased as a result of a 22% increase in production volumes partially offset by lower per unit costs.

It is anticipated that production expenses per boe in 2017 will remain in the $11.75 to $12.25 per boe range. Lower per unit operating costs on the assets acquired in the Viking Acquisition are expected to be offset by cost increases associated with the recently legislated carbon tax in Alberta.

Operating Netback

	Three months ended December 31,			Years ended December 31,		
($/boe)	**2016**	2015	% change	**2016**	2015	% change
Average realized sales	**37.76**	30.23	25	**30.51**	34.43	(11)
Royalty expenses	**(3.56)**	(2.80)	27	**(2.32)**	(3.43)	(32)
Production expenses	**(12.17)**	(12.20)	(0)	**(11.64)**	(12.81)	(9)
Operating field netback	**22.03**	15.23	45	**16.55**	18.19	(9)
Realized commodity hedging gain (loss)	**(0.15)**	8.16	(102)	**3.25**	5.67	(43)
Operating netback	**21.88**	23.39	(6)	**19.80**	23.86	(17)

Operating netback for the fourth quarter of 2016 increased by 9% to $21.88/boe compared to $20.10/boe during the third quarter of 2016. This is attributable to a 17% increase in oil and natural gas liquids prices ($52.88/bbl versus $45.29/bbl) and a 29% increase in natural gas prices ($3.27/mcf versus $2.54/mcf). These positive price impacts were partially offset by a 5% increase in operating expense per boe

($12.17/boe versus $11.58/boe), a realized hedging loss in the fourth quarter of 2016 compared to a hedging gain in the third quarter of 2016 (realized loss of $0.15/boe versus realized gain of $2.10/boe) and a 59% increase in royalty expense per boe ($3.56/boe versus $2.24/boe).

Relative to the same period the prior year, fourth quarter 2016 operating netbacks were 6% lower than the $23.39/boe generated in the fourth quarter of 2015. This was due to a fourth quarter 2016 realized hedging loss of $0.15/boe compared to a realized hedging gain of $8.16/boe in the same quarter of 2015 and royalty expenses per boe that were 27% higher ($3.56/boe versus $2.80/boe). Partially offsetting these impacts were price increases of 35% for oil and natural gas liquids in the fourth quarter of 2016 compared to 2015 ($52.88/bbl versus $39.30/bbl) and natural gas prices that were 23% higher ($3.27/mcf versus $2.66/mcf).

For the year ended December 31, 2016, operating netbacks decreased by 17% to $19.80/boe compared to $23.86/boe for the same period in 2015. The year over year change is attributable to a 4% decrease in oil and natural gas liquids prices ($44.06/bbl versus $45.76/bbl), a 15% decrease in natural gas prices ($2.41/mcf versus $2.85/mcf) and a smaller realized hedging gain of $3.25/boe during 2016 compared to $4.67/boe in 2015. Partially offsetting the pricing and hedging impacts were royalty expenses per boe that were 32% lower ($2.32/boe versus $3.43/boe) and operating expenses that were 9% lower ($11.64/boe versus $12.81/boe).

General and Administrative Expenses

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Gross costs	**$2,500,982**	$2,497,219	0	**$9,470,273**	$9,470,630	(0)
Capitalized costs and recoveries	**(511,369)**	(716,745)	(29)	**(2,075,366)**	(2,231,356)	(7)
General and administrative costs	**$1,989,613**	$1,780,474	12	**$7,394,907**	$7,239,274	2
Total ($/boe)	**$1.89**	$1.94	(3)	**$1.95**	$2.35	(17)

General and administrative (“G&A”) expenses for the fourth quarter of 2016 were $1.89/boe on costs of $1,989,613 compared to $1.89/boe on costs of $1,872,202 in the third quarter of 2016. Fourth quarter 2016 G&A costs on an absolute basis were 6% higher than the previous quarter primarily due to the impact of a 6% increase in production and higher than expected year-end costs.

G&A costs per boe in the fourth quarter of 2016 were 2% lower than the $1.94/boe on costs of $1,780,474 in the same period of 2015, due to a 15% increase in production, partially offset by a 13% increase in absolute G&A costs.

For the year ended December 31, 2016, G&A expenses were $1.95/boe on costs of $7,394,907 compared to $2.35/boe on costs of $7,239,274 during the same period in 2015. On an absolute basis, G&A costs increased by only $155,633 during 2016 compared to 2015, but decreased by 17% on a per boe basis due primarily to a 22% increase in production.

Stock-based Compensation Expenses

Stock-based compensation expenses relating to stock options and restricted share awards were $833,979 and $3,522,794, for the three months and year ended December 31, 2016, compared to $644,466 and $2,941,745 for the same periods in 2015. Stock-based compensation was higher in 2016 due to the increased number of granted options and restricted shares during the year. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

The Company capitalized $334,696 and $1,479,163 of stock-based compensation expenses relating to exploration and development activities for the three months and year ended December 31, 2016, compared to capitalizing $286,999 and $1,419,208 for the same periods in 2015.

For the three months and year ended December 31, 2016 the Company issued 945,000 options at a weighted average exercise price of $3.44 per share and issued 1,214,000 restricted stock units.

During the year ended December 31, 2016, 16,000 stock options at $2.06 per share were exercised for total gross proceeds of $32,960, 12,000 restrictive stock units were settled; and 270,833 stock options expired.

Interest

Interest expense was $615,602 and $3,392,096 for the three months and year ended December 31, 2016, respectively, compared to $1,065,904 and $5,109,876 for the same periods in 2015. The Company had $45,227,189 drawn on its revolving credit facility at December 31, 2016, compared to $82,821,860 drawn at December 31, 2015. Interest expense was lower for the three months and year ended December 31, 2016 compared to the same periods in 2015 due to a lower average amount drawn year-over-year on the revolving credit facility. The average amount drawn over the year in 2016 was approximately $56 million as compared to an average amount drawn of approximately $98 million 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 ("DDA&A").

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Depletion and depreciation	**$17,688,198**	$15,666,107	13	**$64,667,122**	$58,831,540	10
Amortization of undeveloped leases	**202,978**	147,644	37	**759,996**	715,644	6
Accretion	**526,583**	345,340	52	**1,695,817**	1,053,954	61
Total	**$18,417,759**	$16,159,091	14	**$67,122,935**	$60,601,138	11
Depletion and depreciation ($/boe)	**$16.79**	$17.08	(2)	**$17.08**	$19.08	(10)
Amortization ($/boe)	**0.19**	0.16	19	**0.20**	0.23	(13)
Accretion ($/boe)	**0.50**	0.38	32	**0.45**	0.34	32
Total ($/boe)	**$17.48**	$17.62	(1)	**$17.73**	$19.65	(10)

For the fourth quarter of 2016, DDA&A expense was $17.48/boe or $18,417,759 on an absolute basis, compared to $17.73/boe or $17,603,866 during the third quarter of 2016, due to a 6% increase in production, partially offset by lower DDA&A expense on a per boe basis. Relative to the same period in

2015, fourth quarter 2016 DDA&A expense of $17.48/boe was lower than the $17.62/boe for the fourth quarter of 2015. On an absolute basis, DDA&A expense of $18,417,759 was 18% higher in the fourth quarter of 2016 compared to $16,159,091 in the fourth quarter of 2015 due to a 15% increase in production, partially offset by lower DDA&A expense on a per boe basis.

For the year ended December 31, 2016 DDA&A expense was $17.73/boe, compared to $19.65/boe for the same period in 2015. The decrease per boe 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 12% higher in 2016 at $67,122,935, compared to $60,601,138 during the same period in 2015, caused by a 22% 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 months and year ended December 31, 2016, nor does it expect to pay any cash taxes in 2017 or in 2018 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three months and year ended December 31, 2016, a deferred income tax recovery of $403,311 and $4,800,136 were recognized, respectively, compared to a deferred income tax recovery of $345,943 and $8,411,305 for the same respective periods in 2015. There was a deferred tax recovery during the three months and years ended December 31, 2016 and 2015 due to a loss before taxes.

The following table outlines the Company's estimated tax pools as at December 31, 2016:

Tax Pool Category	Deduction Rate	($ millions)
Canadian exploration expense (CEE)	100%	33
Canadian development expense (CDE)	30%	134
Canadian oil and gas property expense (COGPE)	10%	226
Non-capital losses (NCL)	100%	181
Undepreciated capital cost (UCC)	25%	84
Share issue costs and other	various	14
Total		672

Funds from Operations and Net Loss

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Petroleum and natural gas sales	**$39,793,215**	$27,725,228	44	**$115,516,949**	$106,145,723	9
Royalties	**(3,745,935)**	(2,564,759)	(46)	**(8,795,132)**	(10,565,532)	17
Realized gain (loss) on financial instruments	**(162,646)**	7,483,525	(102)	**12,296,313**	17,471,102	(30)
Production expenses	**(12,826,236)**	(11,182,990)	(15)	**(44,067,395)**	(39,496,609)	(12)
General and administration expenses	**(1,989,613)**	(1,780,474)	(12)	**(7,394,907)**	(7,239,274)	(2)
Transaction costs	**–**	–	–	**(596,254)**	(1,044,308)	43
Interest	**(615,602)**	(1,065,904)	42	**(3,392,096)**	(5,109,876)	34
Funds from operations	**$20,453,183**	$18,614,626	10	**$63,567,478**	$60,161,226	6

Funds from operations during the fourth quarter of 2016 were $20,453,183 ($0.15 per share basic and diluted) compared to $16,672,211 ($0.12 per share basic and diluted) in the third quarter of 2016. The increase in the absolute amount is primarily the result of a 29% increase in natural gas prices, a 17%

increase in crude oil and natural gas liquids pricing, transaction costs totaling $596,254 that were incurred during the third quarter of 2016 and a 6% increase in production. The increases were partially offset by a 59% increase in royalty expense, a 12% increase in production expenses, and a realized loss on financial instruments in the fourth quarter of 2016.

Funds from operations for the three months ended December 31, 2016 of $20,453,183 ($0.15 per share basic and diluted) were higher on an absolute basis than the same period in 2015 of $18,614,626 ($0.19 per share basic and diluted), primarily due to a 35% increase in crude oil and natural gas liquids pricing, a 23% increase in natural gas prices and a 15% increase in production. The increase was partially offset by a 46% increase in royalty expense, a 15% increase in production expenses and a realized hedging loss in the fourth quarter of 2016 compared to a realized hedging gain in the fourth quarter of 2015.

Funds from operations during the year ended December 31, 2016 were $63,567,478 ($0.52 per share basic and diluted), compared to $60,161,226 ($0.66 per share basic and diluted) for the same period in 2015. The increase in 2016 was primarily the result of a 22% increase in production, lower royalty expense and lower interest expense, partially offset by a 15% decrease in natural gas pricing, a 4% decrease in crude oil and natural gas liquids pricing, higher production expenses related to increased production and a lower realized hedging gain for 2016 compared to 2015.

	Three months ended December 31,			Years ended December 31,		
($/boe)	**2016**	2015	% change	**2016**	2015	% change
Petroleum and natural gas sales	**$37.76**	$30.23	25	**$30.51**	$34.43	(11)
Royalties	**(3.56)**	(2.80)	(27)	**(2.32)**	(3.43)	32
Realized gain (loss) on financial instruments	**(0.15)**	8.16	(102)	**3.25**	5.67	(43)
Production expenses	**(12.17)**	(12.20)	0	**(11.64)**	(12.81)	9
General and administration expenses	**(1.89)**	(1.94)	3	**(1.95)**	(2.35)	17
Transaction costs	**–**	–	–	**(0.16)**	(0.34)	53
Interest	**(0.58)**	(1.16)	50	**(0.90)**	(1.66)	46
Funds from operations	**$19.41**	$20.29	(4)	**$16.79**	$19.51	(14)

Funds from operations in the fourth quarter of 2016 increased 16% to $19.41/boe from $16.79/boe in the third quarter of 2016 attributable to a 29% increase in natural gas prices and a 17% increase in crude oil and natural gas liquids pricing. The increases were partially offset by a 59% increase in royalty expense per boe, a 5% increase in production expenses per boe and a realized hedging loss in the fourth quarter of 2016 compared to a realized hedging gain in the third quarter of 2016.

The Company had a net loss of $8,424,255 ($0.06 per share basic and diluted) during the three months ended December 31, 2016, compared to a net loss of $3,194,857 ($0.02 per share basic and diluted) for the third quarter of 2016. The Company recorded a higher net loss for the fourth quarter of 2016 compared to the third quarter of 2016 as a result of a higher unrealized loss on financial instruments taken in the fourth quarter of 2016, a loss on the disposition of property, plant and equipment and an impairment to exploration and evaluation assets taken in the fourth quarter of 2016, partially offset by higher revenue in the fourth quarter of 2016.

The Company had a net loss of $8,424,255 ($0.06 per share basic and diluted) during the three months ended December 31, 2016, compared to net income of $5,118,919 ($0.05 per share basic and diluted) for the same period in 2015. Despite higher revenue in the fourth quarter of 2016 compared to 2015, the

Company recorded a net loss in the period compared to net income recorded in the fourth quarter of 2015. Factors contributing to the net loss include a realized hedging loss compared to a realized hedging gain in the same quarter of 2015, higher DDA&A expense in the fourth quarter of 2016, a loss on the disposition of property, plant and equipment as well as an impairment to exploration and evaluation assets taken in the fourth quarter of 2016 compared to a recovery to property, plant and equipment taken in the fourth quarter of 2015.

Tamarack recorded a net loss of $27,822,948 ($0.23 per share basic and diluted) for the year ended December 31, 2016, compared to net loss of $17,328,368 ($0.19 per share basic and diluted) for the same period in 2015. This was due to an unrealized hedging loss in 2016 compared to a unrealized hedging gain in 2015, a lower realized hedging gain in 2016 compared to 2015, higher depletion, depreciation and amortization expense in 2016, higher operating expenses in 2016, a higher loss on the disposition of property, plant and equipment in 2016 and an impairment to exploration and evaluation assets in 2016, partially offset by higher revenue in 2016 and an impairment to property, plant and equipment taken in 2015.

Capital Expenditures (including exploration and evaluation expenditures)

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

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% change	**2016**	2015	% change
Land	**603,512**	$242,713	149	**2,092,324**	$655,429	219
Geological and geophysical	**27,481**	622,839	(96)	**464,338**	675,834	(31)
Drilling and completion	**12,243,027**	13,322,297	(8)	**46,353,198**	41,390,533	12
Equipment and facilities	**1,729,701**	4,304,486	(60)	**6,587,472**	18,363,749	(64)
Capitalized G&A	**181,719**	133,124	37	**889,043**	845,811	5
Office equipment	**77,296**	116,926	(34)	**432,596**	268,747	61
Total capital expenditures	**$14,862,736**	$18,742,385	(21)	**$56,818,971**	$62,200,103	(9)
Property acquisitions	**(247,981)**	2,075,124	(112)	**86,156,054**	57,479,032	50
Proceeds from disposal of property, plant and equipment	**(2,197,925)**	(10,000,000)	(78)	**(2,197,925)**	(12,247,937)	(82)
Total net capital expenditures	**$12,416,830**	$10,817,509	15	**$140,777,100**	$107,431,198	31

During the fourth quarter of 2016, the Company completed and equipped two (2.0 net) previously drilled Viking oil wells in Redwater; drilled, completed and equipped one (1.0 net) horizontal Cardium oil well in Wilson Creek and one (1.0 net) horizontal well in Penny; spudded four (4.0 net) horizontal Cardium oil wells in Wilson Creek; and drilled and abandoned four (4.0) strat-test heavy oil wells in Hatton.

During the fourth quarter of 2016, the Company disposed of its interest in non-core producing properties in Virginia Hills and Wilson Creek, comprised of approximately 16 boe/d (56% liquids) for $2,197,925.

For the year ended December 31, 2016, the Company completed the drilling, completion and equipping of two (1.7 net) Cardium oil wells spudded in 2015; drilled, completed and equipped ten (9.4 net) horizontal Cardium oil wells, two (2.0 net) Viking oil wells, one (1.0 net) oil well in Penny, one (0.8 net) Mannville gas well and two (2.0 net) heavy oil wells. In addition, Tamarack drilled and abandoned four (4.0 net) strat-test heavy oil wells and spudded four (4.0 net) horizontal Cardium oil wells in Wilson Creek. The Company also completed a debottlenecking infrastructure project in the Alder Flats area in order to optimize operations by increasing capacity and reducing operating costs.

2016 Drilling Summary

Excluding strat-test wells but including wells spudded by December 31, 2016		
	Gross	Net
Heavy Oil	2.0	2.0
Viking	2.0	2.0
Mannville	1.0	0.8
Cardium	15.0	14.4
	20.0	19.2

The Company's net undeveloped land was 245,047 acres at the end of 2016.

Impairment

There were no indicators for impairment or impairment reversals identified in 2016, relating to the Company's property, plant and equipment (2015 - $26,175,000 of impairment was recorded for the year ended December 31, 2015 on the Company's property, plant and equipment).

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. For the year ended December 31, 2016, the Company recognized an impairment of $715,000 related to the drill and abandonment of four vertical stratigraphic test wells in the Hatton area.

Liquidity and Capital Resources

Tamarack's net debt, including working capital deficiency excluding the fair value of financial instruments, was $52,316,066 at December 31, 2016, compared to $97,940,880 at December 31, 2015. During the year ended December 31, 2016 the Company reduced net debt by $45,624,814 which improved financial flexibility. Tamarack's December 31, 2016 net debt to fourth quarter annualized funds from operations was 0.6 times, compared to 1.3 times at December 31, 2015.

On December 29, 2016, the Company issued 500,000 flow-through common shares, related to Canadian exploration expenditures ("CEE"), at $5.00 per share for total gross proceeds of $2,500,000. Under the terms of the flow-through share agreement, the Company is required to renounce the $2,500,000 of qualifying oil and natural gas expenditures effective December 31, 2016 and incur the expenditures by December 31, 2017. As of December 31, 2016 the Company has not incurred any of the qualifying oil and natural gas expenditures.

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. As of December 31, 2016 the Company has incurred the full amount of the qualifying oil and natural gas expenditures.

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 year ended December 31, 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 December 31, 2016 there were 137,527,475 common shares, 5,327,051 options and 3,063,167 restricted share awards outstanding. At March 22, 2017 there were 227,670,381 common shares, 5,377,051 options and 3,196,667 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 137,043,779 and 122,235,231 weighted average basic common shares outstanding during the three months and year ended December 31, 2016. No preferred shares of the Company are issued and outstanding.

At December 31, 2016, the Company had 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 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 May 26, 2017.

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.

Subsequent to December 31, 2016 and the successful completion of the Viking Acquisition on January 11, 2017, the Company's syndicate of lenders adjusted the revolving credit facility to $200 million with a $20 million operating facility (collectively the "Facility"). All other terms and conditions of the previous facility remained intact.

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 to be able to fund its 2017 capital program while remaining opportunistic and positioned to take advantage of potential tuck-in acquisitions within its core areas while commodity prices remain low. The equity issuances in 2016, the Penny and Redwater Acquisitions and the Viking Acquisition are consistent with that strategy. In 2017, Tamarack will focus on drilling wells that target a payout of 1.5 years or less, positioning the Company to achieve production per share growth. The Company will also continue to focus on reducing capital costs and operating costs in order to optimize capital efficiencies.

The Company anticipates that funds from operations, together with current cash balances and the Facility, will be sufficient to finance current operations, planned capital expenditures and any working capital requirements for the next twelve months and foreseeable future.

2017 Guidance

Tamarack's 2017 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 while delivering per share growth in production and funds flow from operations. The Company's 2017 guidance:

- Annual average production between 19,000-20,000 boe/d (approximately 55-60% liquids), with 2017 exit production estimated between 20,000-21,000 boe/d (approximately 57-62% liquids);
- Planned capital expenditure range of $165 to $175 million, with first half 2017 expenditures $65 to $75 million;
- Estimated year end 2017 fourth quarter annualized debt to cash flow (including hedges) ratio below 0.9 times with an estimated $70-75 million of liquidity on the Company's existing credit facilities; and
- Using assumed 2017 commodity prices: WTI averaging $55/bbl USD, Edmonton Par price averaging $64.45/bbl, AECO averaging $2.65/GJ and a Canadian/US dollar exchange rate of $0.76.

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 ability 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 December 31, 2016:

	2017	2018	2019	2020	2021	2022	2023
Office lease	641,312	541,718	541,718	262,535	–	–	–
Flow through shares	2,500,000	–	–	–	–	–	–
Take or pay commitments[1]	985,500	985,500	–	–	–	–	–
Rental fee[2]	5,170,125	5,170,125	5,170,125	5,170,125	5,170,125	3,299,093	714,000
Total	9,296,937	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 in the Wilson Creek area is subject to a take-or-pay provision of $9.00/m3. The remaining term is 24 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 additional facilities.

Non–IFRS Measures

This document 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) **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.”

(b) **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):

	December 31, 2016	December 31, 2015
Bank debt	$45,227,189	$82,821,860
Accounts payable and accrued liabilities	25,015,088	31,730,161
Accounts receivable	(16,556,746)	(15,571,507)
Prepaid expenses and deposits	(1,369,465)	(1,039,634)
Net debt	$52,316,066	$97,940,880

Selected Quarterly Information

Three months ended	**Dec. 31, 2016**	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015
Sales volumes								
Natural gas *(mcf/d)*	**31,226**	29,007	27,462	25,818	23,229	22,005	16,972	17,864
Oil and NGL's *(bbls/d)*	**6,249**	5,955	4,959	5,279	6,096	5,049	4,163	5,115
Average boe/d *(6:1)*	**11,453**	10,790	9,536	9,582	9,968	8,717	6,992	8,092
Product prices								
Natural gas *($/mcf)*	**3.27**	2.54	1.62	2.03	2.66	3.04	2.80	2.91
Oil and NGL's *($/bbl)*	**52.88**	45.29	45.35	30.90	39.30	46.56	55.47	48.33
Oil equivalent *($/boe)*	**37.76**	31.82	28.25	22.50	30.23	34.64	39.82	34.75
(000s, except per share amounts)								
Financial results								
Gross revenues	**39,793**	31,588	24,517	19,619	27,725	27,779	25,331	25,311
Funds from operations	**20,453**	16,672	15,364	11,078	18,615	14,618	13,186	13,743
Per share – basic	**0.15**	0.12	0.13	0.11	0.19	0.15	0.16	0.18
Per share – diluted	**0.15**	0.12	0.13	0.11	0.18	0.15	0.16	0.18
Net income (loss)	**(8,424)**	(3,195)	(10,639)	(5,835)	5,119	(15,064)	(2,142)	(5,242)
Per share – basic	**(0.06)**	(0.02)	(0.09)	(0.06)	0.05	(0.15)	(0.03)	(0.07)
Per share – diluted	**(0.06)**	(0.02)	(0.09)	(0.06)	0.05	(0.15)	(0.03)	(0.07)
Additions to property and equipment, net of proceeds	**12,665**	14,497	10,310	17,149	8,743	21,936	14,246	5,028
Net property acquisitions	**(248)**	85,857	–	–	2,075	1,230	54,174	–
Total assets	**663,564**	679,259	542,917	553,135	549,068	549,652	561,977	482,227
Net debt[(1)]	**(52,316)**	(62,817)	(57,791)	(62,696)	(97,941)	(105,837)	(97,280)	(121,159)
Bank debt	**45,227**	48,598	48,630	50,056	82,822	94,423	88,500	112,951
Decommissioning obligations	**112,115**	122,810	68,149	65,643	63,331	61,808	64,883	45,340
Deferred income tax (asset)	**(41,714)**	(41,496)	(42,116)	(38,576)	(36,168)	(35,770)	(33,647)	(28,802)

(1) Excluding fair value of financial instruments

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 of derivative commodity contracts, 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.
- During the third quarter of 2016, Tamarack closed the strategic Penny and Redwater Acquisitions, comprised of certain assets in the Penny area of Southern Alberta and the consolidation of assets in the Redwater and Wilson Creek areas of Alberta on July 12, 2016 and July 25, 2016, respectively; in 2016 these acquisitions added $15,426,229 to oil and natural gas revenue and contributed $85,289 to the 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.

- The Company recorded $596,254 in transaction costs in the third quarter of 2016 related to the Penny and Redwater Acquisitions and $1,044,308 in transaction costs in the second and third quarters of 2015 related to the Wilson Creek / Alder Flats Acquisition.

Selected Annual Information

	2016	2015	2014
Sales volumes			
Natural gas *(mcf/d)*	**28,388**	20,038	13,292
Oil and NGL's *(bbls/d)*	**4,215**	3,703	3,245
Average boe/d *(6:1)*	**10,344**	8,448	5,717
Product prices			
Natural gas *($/mcf)*	**2.41**	2.85	4.28
Oil and NGL's *($/bbl)*	**50.53**	52.06	82.34
Oil equivalent *($/boe)*	**30.51**	34.43	60.38
(000s, except per share amounts)			
Financial Results			
Gross revenues	**115,517**	106,146	125,992
Net income (loss)	**(28,093)**	(17,329)	(25,166)
Per share – basic	**(0.23)**	(0.19)	(0.40)
Per share – diluted	**(0.23)**	(0.19)	(0.40)
Additions to property and equipment, net of proceeds	**140,230**	107,432	288,903
Total assets	**663,564**	549,068	497,578
Working capital (deficiency)(1)	**(52,316)**	(97,941)	(129,799)
Decommissioning obligations	**112,115**	63,331	41,357
Deferred income tax asset	**(41,714)**	(36,168)	(27,299)

(1) Excluding fair value of financial instruments

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

- The volatility in commodity prices and the effect this has had on revenue and net income (loss). The volatility in forward price curves also affects the mark-to-market calculation which results in swings in earnings.
- During the third quarter of 2016, Tamarack closed the strategic Penny and Redwater Acquisitions, comprised of certain assets in the Penny area of Southern Alberta and the consolidation of assets in the Redwater and Wilson Creek areas of Alberta on July 12, 2016 and July 25, 2016, respectively; in 2016 these acquisitions added $15,426,229 to oil and natural gas revenue and contributed $85,829 to the net loss.
- On June 15, 2015, the Company acquired certain working interests in developed petroleum and natural gas properties in the Alder Flats area of Alberta; 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 a major's interests 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 $596,254 in transaction costs in the third quarter of 2016 related to the Penny and Redwater Acquisitions. 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.

- The Company recorded impairment charges on its heavy oil, light oil and certain natural gas related CGU's due to falling oil and gas prices in the amount of $26,175,000 in 2015 and $56,290,000 in 2014. There were no impairments or reversals recorded in 2016.

Critical Accounting Estimates

Management is required to make judgments, assumptions, and estimates in applying its accounting policies which have significant impact on the financial results of the Company. The following outlines the accounting policies involving the use of estimates that are critical to understanding the financial condition and results of operations of the Company:

(a) **Oil and natural gas reserves** – 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. During the financial year end of the Company, the appropriate officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company’s disclosure controls and procedures and have concluded that the Company’s disclosure controls and procedures are effective.

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. During the financial year end of the Company, the appropriate officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company’s internal controls over financial reporting and concluded that the Company’s internal controls over financial reporting are effective. The Company is required to disclose herein any change in the Company's ICFR that occurred during the recent fiscal period that has materially affected, or is reasonably likely to materially affect, the Company’s ICFR.

No material changes in the Company's DCP and its ICFR were identified during the quarter ended December 31, 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 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:

- Pro forma net debt to 2017E cash flow.
- No immediate requirement for equity to fund development of the assets in 2017.

- Estimated production rates in 2017.
- The effect of the MRF on netbacks and economics of future drilling.
- The effect of the recently legislated carbon tax in Alberta.
- Future operating costs.
- 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.
- Future capital expenditures and capital program funding.
- Estimated year end debt to cash flow (including hedges) ratio.
- The Company's capital program and guidance for 2017.
- Derivative contracts and Tamarack's commodity price and foreign exchange rate risk management activities.
- Expectations as to oil and natural gas pricing in 2017.
- Expectations as to oil and natural gas weighting in 2017.
- 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;
- 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 Viking Acquisition 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.

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, 2016, 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.

Drilling Locations

In this MD&A, the 800 net drilling locations identified include 283 proved locations, 507 proved and probable locations and 293 un-booked locations. Proved locations and probable locations account for drilling locations that have associated proved and/or probable reserves, as applicable. Un-booked locations are internal estimates based on prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Un-booked locations do not have attributed reserves or resources. While certain of the un-booked drilling locations have been de-risked by drilling existing wells in relative close proximity to such un-booked drilling locations, the majority of un-booked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and, if drilled, there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.