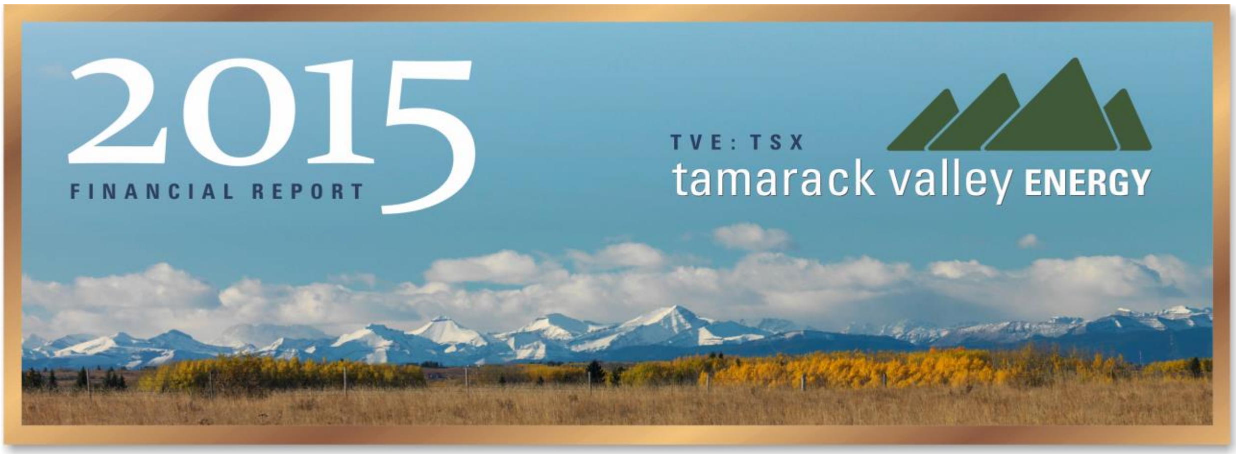

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

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, 2015 and 2014. This MD&A is dated and based on information available on March 23, 2016 and should be read in conjunction with the audited consolidated financial statements and notes for the years ended December 31, 2015 and 2014. 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 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 16 and 17. 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 development oil locations that are economic at various oil prices focused primarily in the Cardium fairway and the Viking fairway in Alberta. 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.

Late in the second quarter of 2015, the Company acquired certain working interests in developed petroleum and natural gas properties in the Alder Flats area of Alberta for an aggregate cash purchase price of $54.8 million, (the "Alder Flats Acquisition").

The Alder Flats Acquisition was accretive to Tamarack and bolsters the Company's strategic Cardium focused land position in the greater Wilson Creek area where the Company's wells have achieved some of the highest production rates in the area. The Alder Flats Acquisition, which closed on June 15, 2015, added 128 (88 net) total sections of land in the greater Wilson Creek / Alder Flats area. On the acquired lands, the Company has identified a total of 70 net economically viable drilling locations, including 40 net high-quality Cardium drilling locations that would be expected to pay out in one year or less at current prices. The Alder Flats Acquisition also added approximately 1,450 boe/d (45% oil & NGLs) of production, including strategic midstream assets consisting of a 100% interest in a 1,000 bbl/d oil battery, a 100% interest in a 6 mmcf/d gas plant and over 220 km of pipeline infrastructure.

Production

	Three months ended December 31,			Years ended December 31,		
	2015	2014	% change	**2015**	2014	% change
Production						
Light oil (bbls/d)	**4,258**	3,772	13	**3,703**	2,932	26
Heavy oil (bbls/d)	**620**	413	50	**602**	257	134
Natural gas liquids (bbls/d)	**1,218**	576	111	**803**	313	157
Natural gas (mcf/d)	**23,229**	17,518	33	**20,038**	13,292	51
Total (boe/d)	**9,968**	7,681	30	**8,448**	5,717	48
Percentage of oil and natural gas liquids	**61%**	62%		**60%**	61%	

Average production for the fourth quarter of 2015 increased by 14% to 9,968 boe/d from 8,717 boe/d in the third quarter of 2015, and exceeded exit guidance production rates of 9,500 to 9,700 boe/d. The production increase was mainly the result of 11 (9.9 net) Cardium oil wells coming on stream late in the quarter which added 2,024 boe/d. This was partially offset by normal declines from existing production as well as TransCanada ("TCPL") pipeline restrictions and resulting third party curtailments, which contributed to approximately 430 boe/d of lost production during the quarter.

Crude oil and natural gas liquids production in the fourth quarter of 2015 increased 21% to average 6,096 bbls/d compared to 5,049 bbls/d in the third quarter of 2015. The production increase was primarily due to the 11 (9.9 net) Cardium oil wells coming on stream late during the quarter which added 1,473 bbls/d, but was partially offset by normal declines from existing production and curtailments which resulted in approximately 130 bbls/d of lost production during the quarter.

Tamarack's oil and natural gas liquids weighting increased to 61% of total production in the fourth quarter of 2015 compared to 58% during the third quarter of 2015. 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 weighting to liquids content compared to the Alder Flats and Brazeau areas, which have a higher natural gas weighting.

Natural gas production averaged 23,229 mcf/d in the fourth quarter of 2015 compared to 22,005 mcf/d in the third quarter of 2015. The production increase was mainly the result of the 11 (9.9 net) Cardium oil wells which came on stream late in the quarter and added 3,303 mcf/d. This production increase was partially offset by normal declines from existing production and TCPL curtailments which resulted in approximately 1,800 mcf/d of lost production during the quarter.

Compared to the prior year, average fourth quarter 2015 production increased by 30% to 9,968 boe/d from 7,681 boe/d in the same period in 2014. This increase is attributable to several factors, including production from assets acquired in the Wilson Creek area of Alberta (the "Wilson Creek Acquisition") in September 2014; assets acquired as part of the Alder Flats Acquisition in the second quarter of 2015; and the successful 2014 and 2015 drilling programs, all of which were partially offset by expected declines from existing production. In the fourth quarter of 2015, the Alder Flats Acquisition added 1,332 boe/d and the Wilson Creek Acquisition added 1,441 boe/d compared to 1,442 boe/d in the fourth quarter of 2014.

Average production for the year ended December 31, 2015 increased by 48% to 8,448 boe/d from 5,717 boe/d in the same period of 2014. The 2015 production increase is attributable to production from the Wilson Creek Acquisition, assets acquired as part of the Alder Flats Acquisition in the second quarter of 2015, and the successful 2014 and 2015 drilling programs. Offsetting the production increase were expected declines from existing production coupled with TCPL curtailments and facility downtime which resulted in approximately 392 boe/d in lost production during 2015 compared to 322 boe/d of lost production in 2014. For the year ended December 31, 2015, the Alder Flats Acquisition added 735 boe/d, while the Wilson Creek Acquisition added 1,372 boe/d compared to 1,442 boe/d during the same period in 2014.

Relative to the fourth quarter of 2015, Tamarack anticipates that production in 2016 will 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. The Company will continue to monitor the price environment, and could elect to reduce its previous 2016 capital budget of $52 to $57 million (which was based on US$40.00/bbl WTI and $2.45/GJ AECO) to $40 million (based on US$33.00/bbl WTI and $2.00/GJ AECO). Depending on which of the two capital programs are executed, the Company would expect production in the first half of 2016 to average between 9,100 and 9,600 boe/d. See page 15 for a more comprehensive summary of 2016 guidance.

Petroleum, Natural Gas Sales and Royalties

	Three months ended December 31,			Years ended December 31,		
	2015	2014	% change	**2015**	2014	% change
Revenue						
Oil and NGLs	**$22,041,711**	$27,539,269	(20)	**$85,308,952**	$105,249,114	(19)
Natural gas	**5,683,517**	6,299,270	(10)	**20,836,771**	20,743,201	0
Total	**$27,725,228**	$33,838,539	(18)	**$106,145,723**	$125,992,315	(16)
Average realized price						
Light oil ($/bbl)	**47.16**	67.83	(30)	**52.06**	87.29	(40)
Heavy oil ($/bbl)	**26.79**	54.84	(51)	**41.98**	68.33	(39)
Natural gas liquids ($/bbl)	**18.22**	36.18	(50)	**19.49**	47.50	(59)
Combined average oil and NGLs ($/boe)	**39.30**	62.87	(37)	**45.76**	82.34	(44)
Natural gas ($/mcf)	**2.66**	3.91	(32)	**2.85**	4.28	(33)
Revenue $/boe	**30.23**	47.89	(37)	**34.43**	60.38	(43)
Benchmark pricing:						
Edmonton Par (Cdn$/bbl)	**51.98**	74.37	(30)	**56.91**	94.09	(40)
Hardisty Heavy (Cdn$/bbl)	**37.04**	67.96	(45)	**45.54**	86.08	(47)
AECO daily index (Cdn$/mcf)	**2.47**	3.58	(31)	**2.69**	4.47	(40)
AECO monthly index (Cdn$/mcf)	**2.64**	3.99	(34)	**2.75**	4.40	(37)
Royalty expenses	**$2,564,759**	$4,380,201	(41)	**$10,565,532**	$16,242,920	(35)
$/boe	**2.80**	6.20	(55)	**3.43**	7.78	(56)
percent of sales	**9**	13	(31)	**10**	13	(23)

Revenue from crude oil, natural gas and associated natural gas liquids sales remained stable at $27,725,228 in the fourth quarter of 2015 relative to $27,779,319 in the third quarter of 2015 but was 18% lower than the $33,838,539 in the fourth quarter of 2014. During the fourth quarter of 2015, natural gas prices averaged $2.66/mcf and the combined oil and natural gas liquids prices averaged $39.30/bbl, compared to $3.04/mcf and $46.56/bbl in the third quarter of 2015 and $3.91/mcf and $62.87/bbl in the fourth quarter of 2014, respectively.

The quarter over quarter stability in revenue was due to a 21% increase in crude oil and natural gas liquids production and a 6% increase in natural gas production, offset by decreases in natural gas and crude oil and natural gas liquids prices of 13% and 16%, respectively.

Fourth quarter 2015 revenue decreased by 18% compared to the same period in 2014, primarily due to a 37% decrease in crude oil and natural gas liquids pricing and a 32% decrease in natural gas prices, partially offset by production increases of 28% for crude oil and natural gas liquids and 33% for natural gas.

The 16% decrease in revenue for the year ended December 31, 2015, compared to the same period in 2014 was primarily caused by a 44% decrease in crude oil and natural gas liquids pricing and a 33% decrease in natural gas prices year over year, partially offset by production increases of 46% for crude oil and natural gas liquids and 51% for natural gas.

The Company's realized crude oil prices for the three months and the years ended December 31, 2015 and 2014 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 the season. Natural gas liquids prices decreased by a greater margin than the Edmonton Par price due to higher than normal propane inventories, higher than normal North American supply and warmer winter conditions causing lower than normal demand. The Company expects this trend to remain consistent for 2016.

The Company's realized heavy oil price for the three months and years ended December 31, 2015 and 2014 generally correlate to the Hardisty Heavy price for those periods.

For the three months and years ended December 31, 2015, 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 December 31, 2015, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,600 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	Cdn $76.51
Crude oil	400 bbls/day	January 1, 2016 – March 31, 2016	WTI fixed price	US $61.50
Crude oil	2,400 bbls/day	April 1, 2016 – June 30, 2016	WTI fixed price	Cdn $76.21
Crude oil	1,200 bbls/day	July 1, 2016 – September 30, 2016	WTI fixed price	Cdn $76.86
Crude oil	900 bbls/day	October 1, 2016 – December 31, 2016	WTI fixed price	Cdn $74.99
Natural gas	5,000 GJ/day	January 1, 2016 – March 31, 2016	AECO fixed price	Cdn $3.06
Natural gas	3,000 GJ/day	April 1, 2016 – October 31, 2016	AECO fixed price	Cdn $2.53

At December 31, 2015, the commodity contracts were fair valued with an asset of $12,468,101 recorded on the balance sheet (December 31, 2014 - $8,470,910) and an unrealized gain of $3,997,191 recorded in earnings for the year ended December 31, 2015.

At December 31, 2015, 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, 2016 – March 31, 2016	AECO fixed price	Cdn $3.02

Since December 31, 2015, the Company has entered into the following derivative contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	600 bbls/day	July 1, 2016 – September 30, 2016	WTI fixed price	Cdn $56.05
Crude oil	800 bbls/day	October 1, 2016 – December 31, 2016	WTI fixed price	Cdn $57.30
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	6,000 GJ/day	January 1, 2017 – March 31, 2017	AECO fixed price	Cdn $2.61

Since December 31, 2015, 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	April 1, 2016 – June 30, 2016	AECO fixed price	Cdn $2.40
Natural gas	2,000 GJ/day	July 1, 2016 – September 30, 2016	AECO fixed price	Cdn $2.44

Royalty expenses for the fourth quarter of 2015 were $2.80/boe or $2,564,759, representing 9% of revenue, compared to $3.81/boe or $3,051,720 for the third quarter of 2015, representing 11% of revenue. The decrease in royalties as a percentage of revenue in the fourth quarter of 2015 compared to the prior quarter was related to the continued fall in commodity prices and a number of new wells being drilled on Company owned lands that have an initial Crown royalty rate incentive of 5%. The Company expects royalty rates to fluctuate as commodity prices change.

For the fourth quarter of 2014 royalty expenses were $6.20/boe or $4,380,201, representing 13% of revenue. This decrease in royalties as a percentage of revenue in the fourth quarter of 2015 compared to the same period in 2014 was related to lower commodity prices and the impact of lower royalties on wells that were drilled late in 2014 and through 2015, partially offset by higher royalty rates from wells acquired in the September 2014 Wilson Creek Acquisition and June 2015 Alder Flats Acquisition.

Royalty expenses for the year ended December 31, 2015 were $3.43/boe or $10,565,532, representing 10% of revenue, compared to $7.78/boe or $16,242,920 for the same period of 2014, representing 13% of revenue. The year over year decrease in 2015 compared to 2014 was related to lower commodity prices and the impact of lower royalties on wells drilled in late 2014 and 2015, partially offset by higher royalty rates from wells acquired in the Wilson Creek Acquisition and Alder Flats Acquisition.

The Company expects royalty rates to remain similar in 2016 compared to 2015 due to continued forecasted low commodity prices and 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. Details of the MRF, including the applicable royalty rates and formulas, are scheduled to be released by March 31, 2016. It is not known at this time the resulting impact on the Company's royalty rates beyond 2016.

Production Expenses

	Three months ended December 31,			Years ended December 31,		
	2015	2014	% change	**2015**	2014	% change
Total production expenses	**$11,182,990**	$8,895,326	26	**$39,496,609**	$28,543,548	38
Total ($/boe)	**$12.20**	$12.59	(3)	**$12.81**	$13.68	(6)

Production expenses for the fourth quarter of 2015 were $12.20/boe compared to $14.05/boe incurred during the third quarter of 2015. The $1.85/boe decrease in the fourth quarter of 2015 resulted from a combination of several factors, including a decrease in trucking and treating costs at the Hatton field following modifications completed in the third quarter which enable the facility to handle higher production volumes. In addition, an optimization debottlenecking project that was commenced in Alder Flats in the third quarter started to have an impact on operating costs in the fourth quarter, plus the Company benefited from new production coming on-stream in the lower-cost Wilson Creek area. On an absolute basis, overall costs remained flat in the fourth quarter of 2015 at $11,182,990 compared to $11,264,333 in the third quarter of 2015. Tamarack will continue to focus efforts on reducing operating costs in 2016 to improve overall netbacks.

Fourth quarter 2015 production expenses were $12.20/boe compared to $12.59/boe for the same quarter of 2014, but increased on an absolute basis by 26% to $11,182,990, compared to $8,895,326 for the same period in 2014. On a per boe basis, the lower production expenses in 2015 resulted from cost reductions at the Wilson Creek and Alder Flats properties and from the impact of higher volumes across fixed costs resulting in lower per unit costs. On an absolute basis, overall costs increased as a result of a 30% increase in production and the facility rental arrangement effective January 2015, partially offset by lower per unit costs.

Production expenses for the year ended December 31, 2015 were $12.81/boe compared to $13.68/boe during the same period in 2014. Absolute production expenses for the year ended December 31, 2015 increased by 38% to $39,496,609, compared to $28,543,548 for the same period in 2014. The decrease in total production costs on a per boe basis resulted from the acquisition of lower per unit cost Wilson Creek properties and cost reduction initiatives across all of the Company's core assets. On an absolute basis, overall costs increased as a result of a 48% increase in production coupled with the facility rental arrangement effective January 2015, partially offset by lower per unit costs.

It is anticipated that production expenses per boe will increase in the first quarter of 2016 compared to the fourth quarter of 2015 due to the expected production decrease in the first quarter. However, production expenses are expected to improve both on an absolute and per boe basis in the second quarter of 2016 following completion of the debottlenecking infrastructure project in Alder Flats, which will redirect production to facilities owned by Tamarack and eliminate third party processing costs.

Operating Netback

	Three months ended December 31,			Years ended December 31,		
($/boe)	**2015**	2014	% change	**2015**	2014	% change
Average realized sales	**30.23**	47.89	(37)	**34.43**	60.38	(43)
Royalty expenses	**(2.80)**	(6.20)	(55)	**(3.43)**	(7.78)	(56)
Production expenses	**(12.20)**	(12.59)	(3)	**(12.81)**	(13.68)	(6)
Operating field netback	**15.23**	29.10	(48)	**18.19**	38.92	(53)
Realized commodity hedging gain (loss)	**8.16**	2.64	209	**5.67**	(1.06)	635
Operating netback	**23.39**	31.74	(26)	**23.86**	37.86	(37)

Operating netback for the fourth quarter of 2015 increased by 6% to $23.39/boe compared to $22.13/boe during the third quarter of 2015. The increase is attributable to several factors, including a realized hedging gain of $8.16/boe in fourth quarter 2015 compared to $5.35/boe in the prior quarter, and a 13% decrease in operating expense per boe ($12.20/boe versus $14.05/boe). These were partially offset by a 16% decrease in oil and natural gas liquids prices ($39.30/bbl versus $46.56/bbl) and a 13% decrease in natural gas prices ($2.66/mcf versus $3.04/mcf).

Relative to the same period the prior year, the fourth quarter 2015 operating netback decreased by 26% to $23.39/boe compared to $31.74/boe in fourth quarter 2014. This was due to a 37% decrease in oil and natural gas liquids prices ($39.30/bbl versus $62.87/bbl) and a 32% decrease in natural gas prices ($2.66/mcf versus $3.91/mcf), partially offset by royalty expenses per boe that were 55% lower ($2.80/boe versus $6.20/boe) and higher realized hedging gains ($8.16/boe versus $2.64/boe).

The operating netback for the year ended December 31, 2015 decreased by 37% to $23.86/boe compared to $37.86/boe during the same period in 2014. This was caused by a 44% decrease in oil and natural gas liquids prices ($45.76/bbl versus $82.34/bbl) and a 33% decrease in natural gas prices ($2.85/mcf versus $4.28/mcf), partially offset by a 56% decline in royalty expenses per boe ($3.43/boe versus $7.78/boe), higher realized hedging gains ($5.67/boe versus $1.06/boe) and a 6% decrease in operating expense per boe ($12.81/boe versus $13.68/boe).

General and Administrative Expenses

	Three months ended December 31,			Years ended December 31,		
	2015	2014	% change	**2015**	2014	% change
Gross costs	**$2,497,219**	$2,395,246	4	**$9,470,630**	$8,200,822	15
Capitalized costs and recoveries	**(716,745)**	(497,605)	44	**(2,231,356)**	(1,720,500)	30
General and administrative costs	**$1,780,474**	$1,897,641	(6)	**$7,239,274**	$6,480,322	12
Total ($/boe)	**$1.94**	$2.69	(28)	**$2.35**	$3.11	(24)

General and administrative expenses for the fourth quarter of 2015 were $1.94/boe on costs of $1,780,474 compared to $2.16/boe on costs of $1,733,423 in the third quarter of 2015. While overall costs remained stable quarter over quarter, the costs per unit decreased by 10% in the fourth quarter of 2015 due to a 14% increase in production.

During the fourth quarter of 2014, general and administrative expenses were $2.69/boe on costs of $1,897,641. The 28% decrease in the fourth quarter 2015 cost per boe was due to the impact of the 30% increase in production and 6% decrease in absolute general and administrative costs.

For the year ended December 31, 2015, general and administrative expenses were $2.35/boe on costs of $7,239,274 compared to $3.11/boe on costs of $6,480,322 during the same period in 2014. While overall costs increased to $7,239,274 in 2015 due to Tamarack's expanded operations, the costs per unit decreased by 24% due to a 48% increase in production.

Stock-based Compensation Expenses

Stock-based compensation expenses relating to stock options and restricted share awards were $644,466 and $2,941,745, for the three months and year ended December 31, 2015, compared to $967,164 and $2,978,228 for the same periods in 2014. Stock-based compensation expense is calculated based on graded vesting periods that are front-end loaded.

The Company capitalized $286,999 and $1,419,208 of stock-based compensation expenses relating to exploration and development activities for the three months and year ended December 31, 2015, compared to capitalizing $458,958 and $1,327,975 for the same periods in 2014.

For the three months ended December 31, 2015 the Company issued 570,000 options at a weighted average exercise price of $2.75 per share and issued 1,416,000 restricted stock units. For the year ended December 31, 2015 the Company issued 727,000 options at a weighted average exercise price of $2.84 per share and issued 1,459,000 restricted stock units.

During the year ended December 31, 2015, 65,416 preferred shares of Tamarack Acquisition Corp., a wholly-owned subsidiary of the Company ("preferred shares") were exchanged for 12,742 common shares on a cashless settlement basis; 29,167 stock options at $3.60 per share were exercised for total gross proceeds of $105,001; 4,333 restrictive stock units were settled with a cash payment of $12,956; and 41,667 stock options expired.

Interest

Interest expense was $1,065,904 and $5,109,876 for the three months and year ended December 31, 2015, respectively, compared to $1,026,478 and $2,528,876 for the same periods in 2014. The Company had $82,821,860 drawn on its revolving credit facility at December 31, 2015, compared to $99,369,896 drawn on its line at December 31, 2014. Interest expense was higher for the three months and year ended December 31, 2015 compared to the same time period in 2014 due to a higher average amount drawn year-over-year on the revolving credit facility. The average amount drawn over the year in 2015 was approximately $98 million as compared to an average amount drawn of approximately $61 million in 2014.

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 December 31,			Years ended December 31,		
	2015	2014	% change	**2015**	2014	% change
Depletion and depreciation	**$15,666,107**	$16,620,313	(6)	**$58,831,540**	$44,840,590	31
Amortization of undeveloped leases	**147,644**	609,381	(76)	**715,644**	2,987,449	(76)
Accretion	**345,340**	272,518	27	**1,053,954**	724,166	46
Total	**$16,159,091**	$17,502,212	(8)	**$60,601,138**	$48,552,205	25
Depletion and depreciation ($/boe)	**$17.08**	$23.52	(27)	**$19.08**	$21.49	(11)
Amortization ($/boe)	**0.16**	0.86	(81)	**0.23**	1.43	(84)
Accretion ($/boe)	**0.38**	0.39	(3)	**0.34**	0.35	(3)
Total ($/boe)	**$17.62**	$24.77	(29)	**$19.65**	$23.27	(16)

Depletion, depreciation, amortization, and accretion (“DDA&A”) expense on a boe basis for the fourth quarter of 2015 was 2% lower at $17.62/boe, compared to $17.89/boe during the third quarter of 2015. This decrease was a result of the Alder Flats Acquisition, increased production from lower-cost Cardium oil properties and an impairment taken in the third quarter to various minor natural gas weighted properties and the Viking oil property. For the fourth quarter of 2015, DDA&A expense was $16,159,091 compared to $14,341,686 during the third quarter of 2015. The 13% increase in total DDA&A expense quarter over quarter was the result of a 14% increase in production partially offset by lower DDA&A expense on a boe basis.

Fourth quarter 2015 DDA&A expense was $17.62/boe, compared to $24.77/boe for the same period in 2014, 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 fourth quarter of 2014 and third quarter of 2015. On an absolute basis, DDA&A expense was 8% lower in the fourth quarter of 2015 at $16,159,091, compared to $17,502,212 in the fourth quarter of 2014, due to lower per unit DDA&A expenses partially offset by the 30% increase in production.

For the year ended December 31, 2015, DDA&A expense on a per boe basis was $19.65/boe, compared to $23.27/boe during the same period in 2014. The decrease in 2015 was a result of the lower amortization rate, increased percentage of production from the lower-cost Cardium and heavy oil properties and impairments to property, plant and equipment taken in the fourth quarter of 2014 and third quarter of 2015. On an absolute basis, DDA&A expense for the year ended December 31, 2015 was $60,601,138, an increase of 25% compared to the $48,552,205 for the same period in 2014. This was due to a 48% increase in production, partially offset by lower per unit depletion, depreciation and accretion expense on a boe basis.

Income Taxes

The Company did not incur any cash tax expense in the three months and year ended December 31, 2015, 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 and year ended December 31, 2015, a deferred income tax recovery of $345,943 and a deferred income tax recovery of $8,411,305 was recognized, compared to a deferred income tax recovery expense of $11,234,034 and $5,958,798 for the same periods in 2014. There was a deferred tax recovery during the three months and years ended December 31, 2015 and 2014 due to a loss before taxes.

On June 29, 2015, the general corporate income tax rate for Alberta increased to 12% from 10% effective July 1, 2015.

The following table outlines the Company’s estimated tax pools as at December 31, 2015:

Tax Pool Category	Deduction Rate	($ millions)
Canadian exploration expense (CEE)	100%	31
Canadian development expense (CDE)	30%	129
Canadian oil and gas property expense (COGPE)	10%	184
Non-capital losses (NCL)	100%	160
Undepreciated capital cost (UCC)	25%	58
Share issue costs and other	various	12
Total		574

Funds from Operations and Net Income

	Three months ended December 31,			Years ended December 31,		
	2015	2014	% change	**2015**	2014	% change
Petroleum and natural gas sales	**$27,725,228**	$33,838,539	(18)	**$106,145,723**	$125,992,315	(16)
Royalties	**(2,564,759)**	(4,380,201)	41	**(10,565,532)**	(16,242,920)	35
Realized gain (loss) on financial instruments	**7,483,525**	1,867,843	301	**17,471,102**	(2,204,894)	892
Production expenses	**(11,182,990)**	(8,895,326)	(26)	**(39,496,609)**	(28,543,548)	(38)
General and administration expenses	**(1,780,474)**	(1,897,641)	6	**(7,239,274)**	(6,480,322)	(12)
Transaction costs	**–**	(378,923)	100	**(1,044,308)**	(3,820,275)	73
Interest	**(1,065,904)**	(1,026,478)	(4)	**(5,109,876)**	(2,528,876)	(102)
Funds from operations	**$18,614,626**	$19,127,813	(3)	**$60,161,226**	$66,171,480	(9)

Funds from operations during the fourth quarter of 2015 were $18,614,626 ($0.19 per share basic and diluted) compared to $14,618,184 ($0.15 per share basic and diluted) for the third quarter of 2015. The increase is primarily the result of a higher realized hedging gain, a 14% increase in production and a lower royalty expense, partially offset by the 16% decrease in crude oil and natural gas liquids pricing and a 13% decrease in the natural gas price.

Funds from operations during the three months ended December 31, 2015 were $18,614,626 ($0.19 per share basic and diluted), compared to $19,127,813 ($0.25 per share basic and diluted) for the same period in 2014. The 3% decrease was primarily the result of a 37% decrease in crude oil and natural gas liquids pricing, a 32% 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 fourth quarter of 2015 compared to the same period in 2014, a 30% increase in production and lower royalty expenses.

Funds from operations during the year ended December 31, 2015 were $60,161,226 ($0.66 per share basic and diluted), compared to $66,171,480 ($1.05 per share basic and diluted) for the same period in 2014. The decrease was primarily the result of a 44% decrease in crude oil and natural gas liquids pricing, a 33% decrease in natural gas pricing, higher interest expense and higher production expenses related to increased production, all of which was partially offset by a realized hedging gain for 2015 (compared to a realized hedging loss in 2014), a 48% increase in production and lower royalty expenses.

	Three months ended December 31,			Years ended December 31,		
($/boe)	**2015**	2014	% change	**2015**	2014	% change
Petroleum and natural gas sales	**$30.23**	$47.89	(37)	**$34.43**	$60.38	(43)
Royalties	**(2.80)**	(6.20)	55	**(3.43)**	(7.78)	56
Realized gain (loss) on financial instruments	**8.16**	2.64	209	**5.67**	(1.06)	636
Production expenses	**(12.20)**	(12.59)	3	**(12.81)**	(13.68)	6
General and administration expenses	**(1.94)**	(2.69)	28	**(2.35)**	(3.11)	24
Transaction costs	**–**	(0.54)	100	**(0.34)**	(1.83)	81
Interest	**(1.16)**	(1.45)	20	**(1.66)**	(1.21)	(37)
Funds from operations	**20.30**	27.07	(25)	**$19.51**	$31.71	(38)

Fourth quarter 2015 funds from operations increased to $20.30/boe from $18.23/boe in the third quarter of 2015 due to a 53% increase in realized hedging gain, a 13% decrease in production expenses per boe and a 27% decrease in royalty expense per boe, partially offset by decreases in crude oil and natural gas liquids prices and natural gas prices of 16% and 13%, respectively.

The Company had net income of $5,118,919 ($0.05 per share basic and diluted) during the three months ended December 31, 2015, compared to a net loss of $15,063,870 ($0.15 per share basic and diluted) for the third quarter of 2015. The Company recorded net income for the three months ended December 31, 2015 as compared to the third quarter of 2015 as a result of an impairment to property, plant and equipment in the third quarter, partially offset by a lower unrealized gain on financial instruments taken in the fourth quarter of 2015.

The Company had net income of $5,118,919 ($0.05 per share basic and diluted) during the three months ended December 31, 2015, compared to a net loss of $38,991,202 ($0.50 per share basic and diluted) for the same period in 2014. This was a result of higher realized hedging gains in the fourth quarter of 2015 compared to the fourth quarter of 2014 and a 30% increase in production, as well as an impairment to property, plant and equipment taken in the fourth quarter 2014. These impacts were partially offset by several factors, including a 37% decrease in crude oil and natural gas liquids pricing; a 32% decrease in natural gas pricing; higher production expenses related to increased production; a lower unrealized hedging gain in the fourth quarter of 2015 compared to the same quarter of 2014; and a higher deferred income tax recovery in the fourth quarter of 2014 compared to the fourth quarter of 2015.

The Company had a net loss of $17,328,368 ($0.19 per share basic and diluted) for the year ended December 31, 2015, compared to net loss of $25,167,361 ($0.40 per share basic and diluted) for the same period in 2014. The net loss was lower for 2015 as compared to 2014 as a result of lower impairment to property, plant and equipment, a higher realized hedging gain, a higher deferred income tax recovery and a 48% increase in production, but was partially offset by a 44% decrease in crude oil and natural gas liquids pricing, a 33% decrease in natural gas pricing, higher production expenses related to the increased production and a lower unrealized hedging gain.

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,		
	2015	2014	% change	**2015**	2014	% change
Land	**242,713**	$3,495,452	(93)	**$655,429**	$6,435,639	(90)
Geological and geophysical	**622,839**	(82,776)	(852)	**675,834**	602,190	12
Drilling and completion	**13,322,297**	39,244,024	(66)	**41,390,533**	119,753,138	(65)
Equipment and facilities	**4,304,486**	10,776,413	(60)	**18,363,749**	26,680,355	(31)
Capitalized G&A	**133,124**	(215,185)	(162)	**845,811**	426,470	98
Office equipment	**116,926**	10,658	997	**268,747**	56,387	377
Total capital expenditures	**$18,742,385**	$53,228,586	(65)	**$62,200,103**	$153,954,179	(60)
Property acquisition	**2,075,124**	–	–	**57,479,032**	166,056,562	(65)
Proceeds from disposal of property, plant and equipment	**(10,000,000)**	(26,454,191)	(62)	**(12,247,937)**	(31,107,281)	(61)
Total net capital expenditures	**$10,817,509**	$26,774,395	(60)	**$107,431,198**	$288,903,460	(63)

During the fourth quarter of 2015, the Company equipped 2 (1.60 net) previously drilled and completed horizontal Cardium wells; completed and equipped 3 (2.8 net) horizontal Cardium wells; drilled, completed and equipped 4 (3.4 net) horizontal Cardium oil wells; and spudded 2 (1.7 net) horizontal Cardium oil wells all in the Wilson Creek/Alder Flats area. The Company continued debottlenecking infrastructure in the recently acquired Alder Flats area in order to optimize operations by increasing capacity and reducing operating costs. This project is expected to be completed by the end of the first quarter of 2016.

During the fourth quarter of 2015, the Company disposed of its interest in certain oil and gas infrastructure assets for $10,000,000, bringing the disposition total in 2015 to $12,247,937. Other completed non-core dispositions comprised 90 boe/d and 8 (7 net) sections of undeveloped land.

For the year ended December 31, 2015, the Company completed and equipped 3 (1.4 net) previously drilled horizontal Cardium wells; drilled, completed and equipped 15 (13.8 net) horizontal Cardium wells; and spudded 2 (1.7 net) horizontal Cardium oil wells all in the Wilson Creek/Alder Flats area. The Company completed construction on the Hatton heavy oil battery and continued debottlenecking infrastructure in the recently acquired Alder Flats area to optimize operations by increasing capacity and reducing operating costs. This project is expected to be completed by the end of the first quarter of 2016.

During 2015 the Company completed 11 tuck-in acquisitions in the Wilson Creek and Alder Flats areas totalling $57.5 million. The main tuck-in acquisition was the Alder Flats Acquisition completed in the second quarter of 2015 (see page 2 for more details). In total, the Company added 168 (95 net) total sections of land; increased drilling inventory by 88 locations; added 1,545 boe/d (43% oil & NGLs) of production; and added strategic midstream assets consisting of a 100% interest in a 1,000 bbl/d oil battery, a 100% interest in a 6 mmcf/d gas plant and over 220 km of pipeline infrastructure.

2015 Drilling Summary (including wells spudded by December 31, 2015)		
	Gross	Net
Cardium	17.0	15.6
	17.0	15.6

The Company's net undeveloped land was 212,118 acres at the end of the fourth quarter of 2015.

Impairment

An impairment charge of $26,175,000 (2014 - $56,290,000) was recorded for the year ended December 31, 2015 on the Company's property, plant and equipment. The impairment charge is the result of a dramatic and sustained decrease in current and forecast forward commodity prices. The impairment recognized in 2015 relates to the Quaich ($816,000), Hanlan ($712,000), Minor Properties ($561,000), Peace River Arch ($1,108,000) and Viking Oil ($25,769,000) Cash Generating Units ("CGU") with a minor impairment reversal of $2,791,000 due to enhanced reserve bookings on the Heavy Oil CGU. The recoverable value as at December 31, 2015 of these CGU's was Quaich $3,934,000, Hanlan nil, Minor Properties nil, Peace River Arch $1,700,000, Viking Oil $43,417,000 and Heavy Oil $9,580,000. The recoverable value of the Company's CGU's was estimated at the value in use based on the net present value of before tax cash flows from proved plus probable reserves estimated by the Company at varying discount rates between 8% to 25% depending on the particular characteristics of the CGU. The prices used to estimate value in use are the average of those used by three independent industry reserve evaluators. As the recoverable amount of the CGUs are sensitive to a decrease in commodity prices, further impairment charges could be recorded in future periods.

Liquidity and Capital Resources

Tamarack's net debt, including working capital deficiency excluding the fair value of financial instruments, was $97,940,880 at December 31, 2015, compared to $129,798,673 at December 31, 2014. During the year ended December 31, 2015 the Company reduced net debt by $31,857,793 which improved financial flexibility. Tamarack's December 31, 2015 net debt to annualized funds from operations in the fourth quarter of 2015 was 1.3 times, compared to 1.7 times at December 31, 2014.

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.

On December 3, 2015, the Company issued 37,600 flow-through common shares, related to Canadian exploration expenditures, at $3.55 per share for total gross proceeds of $133,480. Certain officers, directors and employees acquired 28,400 flow-through common shares for gross proceeds of $100,820.

On June 3, 2015, the Company completed a bought deal financing by issuing 17,197,000 common shares at $3.78 per share for total gross proceeds of $65,004,660. Certain officers, directors and employees acquired 18,600 common shares for gross proceeds of $70,308. On June 10, 2015, the over-allotment option was exercised, resulting in the issuance of 2,579,550 common shares at $3.78 per share for total gross proceeds of $9,750,699. The proceeds of this financing were used, in part, to complete the $54.8 million Alder Flats Acquisition that closed on June 15, 2015.

On June 3, 2015, the Company also issued 2,186,800 flow-through common shares related to Canadian development expenditures at $4.15 per share for total gross proceeds of $9,075,220. Certain officers, directors and employees acquired 26,800 flow-through common shares for gross proceeds of $111,220.

During the year ended December 31, 2015, 65,416 preferred shares were exchanged into 12,742 common shares on cashless basis and 29,167 stock options at $3.60 per share were exercised for total gross proceeds of $105,001.

At December 31, 2015, there were 99,971,325 common shares, 1,110,584 preferred shares, 4,668,884 options and 1,861,167 restricted share awards outstanding. At March 24, 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. At December 31, 2014 there were 77,928,466 common shares, 1,176,000 preferred shares, 4,147,386 options and 406,500 restricted share awards outstanding. The Company had 99,945,577 and 90,661,207 weighted average basic common shares outstanding during the three months and year ended December 31, 2015.

At December 31, 2015, 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, 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.

Priority for the Company in 2015 was to maintain its strong balance sheet by limiting capital spending (excluding acquisitions) to less than cash flow from operations. During 2015, Tamarack was able to increase average production by 48% while reducing debt by 25% and continuing to build its drilling inventory and infrastructure footprint in the Wilson Creek and Alder Flats areas.

With the recent decrease in commodity prices and continued volatility in the oil and gas industry, Tamarack's strategy remains focused on preserving its balance sheet by adjusting capital spending relative to changes in commodity prices. The Company wants to maintain flexibility with its balance sheet to be opportunistic and take advantage of potential tuck-in acquisition opportunities within its core areas while commodity prices are low. The equity issuance completed on March 18, 2016, was consistent with that strategy. Pro-forma this equity financing, net debt at December 31, 2015 would have been approximately $57 million. Tamarack will focus on drilling wells that target a return on capital cost payout of 1.5 years or less. Tamarack 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 top priority of protecting its top tier 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 high quality drilling inventory that achieves 1.5 year payout or less in the current pricing environment, the Company began to adjust capital spending as a result of the continued volatility in commodity prices. The Company's 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 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.
- At least $88 million of liquidity maintained on bank lines based on the current credit facility.

Commitments

The following table summarizes the Company's commitments at December 31, 2015:

	2016	2017	2018	2019	2020	2021	2022	2023
Office lease	680,713	641,312	541,718	541,718	262,535	–	–	–
Take or pay commitments (1)	988,200	985,500	985,500	–	–	–	–	–
Drilling commitments (2)	6,550,000	–	–	–	–	–	–	–
Rental fee (3)	5,170,125	5,170,125	5,170,125	5,170,125	5,170,125	5,170,125	3,299,093	714,000
Total	13,389,038	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 37 months.
2. Drilling and completion commitments related to the farm-in entered into on August 19, 2013. Overall 15 net wells must 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 December 31, 2015, the Company had satisfied approximately 62% to 83% of the drilling commitment and estimates the capital expenditures to fulfill the remainder of this commitment will be between $7 and $20 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.

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 December 31,		Years ended December 31,	
	2015	2014	**2015**	2014
Cash provided by operating activities	**$23,449,324**	$21,629,454	**$61,388,940**	$67,044,206
Abandonment expenditures	**985**	266,979	**155,559**	678,886
Changes in non-cash working capital	**(4,835,683)**	(2,768,619)	**(1,383,273)**	(1,551,612)
Funds from operations	**$18,614,626**	$19,127,814	**$60,161,226**	$66,171,480
Funds from operation per share -basic	**$ 0.19**	$ 0.25	**$ 0.66**	$ 1.05
Funds from operation per share -diluted	**$ 0.18**	$ 0.25	**$ 0.66**	$ 1.05

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

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

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

	December 31, 2015	December 31, 2014
Cash and cash equivalents	**$ –**	$830,104
Accounts receivables	**15,571,507**	20,370,676
Prepaid expenses	**1,039,634**	810,983
Accounts payable and accrued liabilities	**(31,730,161)**	(51,610,436)
Bank debt	**(82,821,860)**	(100,200,000)
Net debt	**$(97,940,880)**	$(129,798,673)

Selected Quarterly Information

Three months ended	**Dec. 31, 2015**	Sep. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2014	Sep. 30, 2014	Jun. 30, 2014	Mar. 31, 2014
Sales volumes								
Natural gas *(mcf/d)*	**23,229**	22,005	16,972	17,864	17,518	12,462	12,033	11,093
Oil and NGL's *(bbls/d)*	**6,096**	5,049	4,163	5,115	4,761	3,688	3,197	2,333
Average boe/d *(6:1)*	**9,968**	8,717	6,992	8,092	7,681	5,765	5,203	4,182
Product prices								
Natural gas *($/mcf)*	**2.66**	3.04	2.80	2.91	3.91	4.13	4.37	4.93
Oil and NGL's *($/bbl)*	**39.30**	46.56	55.47	48.33	62.87	90.19	94.65	93.23
Oil equivalent *($/boe)*	**30.23**	34.64	39.82	34.75	47.89	66.62	68.27	65.09
(000s, except per share amounts)								
Financial results								
Gross revenues	**27,725**	27,779	25,331	25,311	33,839	35,333	32,322	24,498
Funds from operations	**18,615**	14,618	13,186	13,743	19,128	15,809	17,790	13,445
Per share – basic	**0.19**	0.15	0.16	0.18	0.25	0.26	0.29	0.26
Per share – diluted	**0.18**	0.15	0.16	0.18	0.25	0.26	0.29	0.25
Net income (loss)	**5,119**	(15,064)	(2,142)	(5,242)	(38,991)	6,791	5,243	1,791
Per share – basic	**0.05**	(0.15)	(0.03)	(0.07)	(0.50)	0.11	0.09	0.03
Per share – diluted	**0.05**	(0.15)	(0.03)	(0.07)	(0.50)	0.11	0.08	0.03
Additions to property and equipment, net of proceeds	**8,743**	21,936	14,246	5,028	26,774	30,318	40,742	25,012
Net property acquisitions	**2,075**	1,230	54,174	–	–	166,057	–	–
Total assets	**549,068**	549,652	561,977	482,227	497,578	525,003	319,065	288,608
Working capital (deficiency)[1]	**(97,941)**	(105,837)	(97,280)	(121,159)	(129,799)	(121,684)	(59,490)	(37,130)
Bank debt[2]	**82,822**	94,423	88,500	112,951	100,200	100,275	43,735	17,494
Decommissioning obligations	**63,331**	61,808	64,883	45,340	41,357	36,732	20,956	20,484
Deferred income tax (asset)	**(36,168)**	(35,770)	(33,647)	(28,802)	(27,299)	(16,870)	(17,743)	(19,681)

(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 affects the mark-to-market calculation, which 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 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 $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.

Selected Annual Information

	2015	2014	2013
Sales volumes			
Natural gas *(mcf/d)*	**20,038**	13,292	8,191
Oil and NGL's *(bbls/d)*	**3,703**	3,245	1,911
Average boe/d *(6:1)*	**8,448**	5,717	3,276
Product prices			
Natural gas *($/mcf)*	**2.85**	4.28	3.42
Oil and NGL's *($/bbl)*	**52.06**	82.34	85.80
Oil equivalent *($/boe)*	**34.43**	60.38	58.59
(000s, except per share amounts)			
Financial Results			
Gross revenues	**106,146**	125,992	70,059
Net income (loss)	**(17,329)**	(25,166)	14,813
Per share – basic	**(0.19)**	(0.40)	0.44
Per share – diluted	**(0.19)**	(0.40)	0.44
Additions to property and equipment, net of proceeds	**107,432**	288,903	57,541
Total assets	**549,068**	497,578	269,707
Working capital (deficiency)[1]	**(97,941)**	(129,799)	(81,764)
Decommissioning obligations	**63,331**	41,357	19,802
Deferred income tax asset	**(36,168)**	(27,299)	(19,467)

(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.
- 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. On October 9, 2013 the Company acquired Sure Energy. Since the closing, this acquisition added $4,214,745 to oil and natural gas revenue and contributed $239,547 to net income in 2013.
- The Company recorded a $10,053,750 gain on the Sure Acquisition as the fair value paid was less than the fair value of the assets acquired.
- The Company recorded $1,044,308 in transaction costs in the second and third quarters of 2015 related the Alder Flats Acquisition, $3,820,275 in transaction costs in the third and fourth quarter of 2014 related to the Wilson Creek Acquisition and recorded $1,645,116 in transaction costs in the fourth quarter of 2013 related to the Sure 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.

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 Natural 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 shares 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 Chief Executive Officer and Chief Financial Officer are responsible for the design and operating effectiveness of internal controls over financial reporting ("ICFR") and disclosure controls and procedures ("DCP") of the Company.

In accordance with National Instrument NI 52-109, the Chief Executive Officer and Chief Financial Officer have filed certifications that DCP and ICFR have been adequately designed and are operating effectively, and that there have been no changes in ICFR that materially affected, or are reasonably likely to materially affect, ICFR.

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 forecasted. 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.

The Alberta government is in the process of concluding a royalty review which could impact the amount of royalties payable in the future.

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", "project", "potential", "target", "intend", "focus", "identify", "manage", "want", "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.
- Debottlenecking of infrastructure in the Wilson Creek / Alder Flats area.
- Adjustments to the capital budget to account for commodity price changes.

- Future operating costs on a boe basis.
- Reduction of operating costs on the assets purchased in the Alder Flats Acquisition.
- Future impairment charges related to CGU's
- 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, Tamarack's credit facilities.
- 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.
- The ability of the Company to take advantage of opportunities that may arise due to commodity price volatility.
- Disposition of non-core assets.

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 revised 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.