MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL RESULTS

The following Management's Discussion and Analysis ("MD&A") is a review of the operational and financial results and outlook for Tamarack Valley Energy Ltd. ("Tamarack" or the "Company") for the three and nine months ended September 30, 2014 and 2013. This MD&A is dated and based on information available on November 13, 2014 and should be read in conjunction with the unaudited condensed consolidated interim financial statements and notes for the three and nine months ended September 30, 2014 and 2013. Additional information relating to Tamarack, including Tamarack's annual information form, is available on SEDAR at www.sedar.com.

The condensed consolidated interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). The Company uses certain non-IFRS and additional IFRS measures in this MD&A. For a discussion of those measures, including the method of calculation, please refer to section entitled "Non-IFRS and Additional IFRS Measures" located on pages 13 & 14. 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 ("NI 51–101"). 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 a Calgary based, oil and natural gas exploration and production company focused on delivering a superior rate of return on capital investment. Tamarack is committed to long-term growth through 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 resource plays that will provide long-life reserves, and using a rigorous, proven modeling process to carefully manage risk while identifying opportunities. The Company's long term strategy involves the identification and development of assets in four different core plays, which will serve to diversify risk and increase capital optionality to enable proper risk management while delivering superior rates of return. To date, Tamarack has established two core plays: Cardium oil play in Lochend, Garrington and the greater Pembina area, including Buck Lake, Wilson Creek and Alder Flats, and the shallow Viking oil play in Redwater and Westlock.

On September 30, 2014, the Company acquired certain working interests in developed petroleum and natural gas properties in the Wilson Creek area of Alberta for an aggregate cash purchase price of $168.5 million, prior to closing adjustments (the "Wilson Creek Acquisition").

The Wilson Creek Acquisition is highly accretive to Tamarack and further bolsters the Company's strategic Cardium focused land position in the Wilson Creek area where the Company has achieved some of the highest production rates in the area. As of September 30, 2014, the Wilson Creek Acquisition adds approximately 1,600 boe/d (44% oil & NGLs) of high netback production, including 18,360 (13,728 net) acres of undeveloped land and strategic operated midstream assets consisting of a 100% interest in a 3,800 bbl/d oil battery and a 52% interest in a 30 mmcf/d gas plant.

Production

	Three months ended September 30,			Nine months ended September 30,		
	2014	2013	% change	**2014**	2013	% change
Production						
Oil and natural gas liquids (bbls/d)	**3,272**	1,812	81	**2,816**	1,635	72
Heavy oil (bbls/d)	**416**	55	656	**262**	40	555
Natural gas (mcf/d)	**12,462**	7,767	60	**11,868**	7,464	59
Total (boe/d)	**5,765**	3,162	82	**5,056**	2,919	73
Percentage of oil and natural gas liquids	**64%**	59%		**61%**	57%	

On September 30, 2014, the Company closed the Wilson Creek Acquisition that, based on field estimates, added approximately 1,510 boe/d of production for the month of October, 2014.

Production for the third quarter of 2014 increased by 11% to 5,765 boe/d from 5,203 boe/d in the second quarter of 2014, and increased by 82% from 3,162 boe/d in the third quarter of 2013. The 11% production increase during the third quarter of 2014, compared to the second quarter of 2014, was the result of 8 (6.5 net) new Viking oil wells coming on-stream adding 241 boe/d to the quarter average, 8 (7.0 net) new Cardium oil wells coming on-stream during the quarter in the Blue Rapids and Wilson Creek areas, adding 654 boe/d to the quarter average and 2 (2.0 net) new heavy oil wells in Hatton adding 126 boe/d to the third quarter average. Additionally an incremental 336 boe/d was added to the quarter average by wells that came on late in the second quarter, offset by expected declines from existing production and

from unscheduled Trans Canada Pipeline facility downtime and curtailments which resulted in 469 boe/d of lost production. The Company expects further unscheduled downtime in the next couple quarters associated with Trans Canada Pipeline maintenance.

Crude oil and natural gas liquids production in the third quarter of 2014 was up 15% to 3,688 bbls/d compared to 3,197 bbls/d in the second quarter of 2014. Crude oil and natural gas liquids production increased by 15% quarter-over-quarter as a result of 8 (6.5 net) new Viking oil wells coming on-stream adding 231 bbls/d to the quarter average, 8 (7.0 net) new Cardium oil wells coming on-stream during the quarter in the Blue Rapids and Wilson Creek areas, adding 508 bbls/d to the quarter average and 2 (2.0 net) new heavy oil wells in Hatton adding 118 bbls/d to the third quarter average. An incremental 114 bbls/d was added to the quarter average by wells that came on late in the second quarter offset by expected declines from existing production and from unscheduled facility downtime and curtailments which resulted in 120 bbls/d of lost production. The percentage of oil and natural gas liquids weighting increased to 64% of total production in the third quarter of 2014 compared to 61% of total production during the second quarter of 2014. The Company expects its percentage of oil and natural gas liquids weighting to fluctuate between 55% and 64% depending on the timing of production additions in the Redwater and Wilson Creek areas, where production will be weighted higher to liquids content.

Natural gas production was 12,462 mcf/d in the third quarter of 2014 compared to 12,033 mcf/d in the second quarter of 2014. Production increased quarter-over-quarter due to 8 (6.5 net) new Viking oil wells coming on-stream adding 56 mcf/d to the quarter average, 8 (7.0 net) new Cardium oil wells coming on-stream during the quarter in the Blue Rapids and Wilson Creek areas, adding 875 mcf/d to the quarter average and 2 (2.0 net) new heavy oil wells in Hatton adding 46 mcf/d to the third quarter average. An incremental 1,335 mcf/d was added to the quarter average by wells that came on late in the second quarter, offset by expected declines from existing production and from unscheduled Trans Canada Pipeline facility downtime and curtailments which resulted in 2,093 mcf/d of lost production. The Company expects further unscheduled downtime in the next couple quarters associated with Trans Canada Pipeline maintenance.

Increases in production for the three and nine months ended September 30, 2014, when compared to the same period in 2013, were due to production from assets acquired as part of the Sure Energy Inc. (“Sure”) acquisition (the “Sure Acquisition”) completed in October, 2013, and the successful 2013 and 2014 drilling programs, offset by expected declines from existing production.

Petroleum, Natural Gas Sales and Royalties

	Three months ended September 30,			Nine months ended September 30,		
	2014	2013	% change	**2014**	2013	% change
Revenue						
Oil and NGLs	**$30,597,130**	$16,945,521	81	**$77,709,845**	$41,160,848	89
Natural gas	**4,736,126**	2,136,668	122	**14,443,931**	6,673,988	116
Total	**$35,333,256**	$19,082,189	85	**$92,153,776**	$47,834,836	93
Average realized price						
Oil and NGLs ($/bbl)	**90.19**	98.65	(9)	**92.49**	90.01	3
Natural gas ($/mcf)	**4.13**	2.99	38	**4.46**	3.28	36
Combined average ($/boe)	**66.62**	65.60	2	**66.77**	60.03	11
Benchmark pricing:						
Edmonton Par (Cdn$/bbl)	**97.72**	104.68	(7)	**100.46**	95.06	6
AECO daily index (Cdn$/mcf)	**4.00**	2.44	64	**4.77**	3.05	56
AECO monthly index (Cdn$/mcf)	**4.20**	2.81	50	**4.53**	3.15	44
Royalty expenses	**$4,701,831**	$2,131,804	121	**$11,862,719**	$5,459,756	117
$/boe	**8.87**	7.33	21	**8.60**	6.85	26
percent of sales	**13**	11	18	**13**	11	18

Revenue from crude oil, natural gas and associated natural gas liquids sales increased by 9% to $35,333,256 in the third quarter of 2014 from $32,322,265 in the second quarter of 2014 and increased by 85% as compared to $19,082,189 in the third quarter of 2013. Natural gas prices averaged $4.13/mcf and oil and natural gas liquids prices averaged $90.19/bbl in the third quarter of 2014 as compared to $4.37/mcf and $94.65/bbl in the second quarter of 2014 and compared to $2.99/mcf and $98.65/bbl in the third quarter of 2013, respectively.

The 9% increase in revenue during the third quarter of 2014, when compared to the second quarter of 2014, was primarily the result of the 15% increase in crude oil and natural gas liquids production, a 4% increase in natural gas production, partially offset by a 5% decrease in natural gas pricing and a 5% decrease in crude oil and natural gas liquids pricing.

The 85% increase to revenue in the third quarter of 2014, compared to the third quarter of 2013, was primarily caused by a 98% increase in crude oil and natural gas liquids production, a 60% increase in natural gas production and a 38% increase in natural gas pricing, partially offset by a 9% decrease in crude oil and natural gas liquids pricing.

The 93% increase to revenue in the first nine months of 2014, compared to the same period in 2013, was primarily caused by an 84% increase in crude oil and natural gas liquids production, a 59% increase in natural gas production, a 3% increase in crude oil and natural gas liquids pricing and a 36% increase in natural gas pricing.

The Company's realized crude oil and natural gas liquids prices for the three and nine months ended September 30, 2014 and 2013 generally correlate to the Edmonton Par Canadian price posting for the same period. Natural gas liquids are priced at varying discounts to Edmonton Par Canadian price posting

depending on market conditions, pipeline capacity and the season.

The Company's realized natural gas prices for the three and nine months ended September 30, 2014, excluding the impact of physical natural gas hedges (realized natural gas price for the three and nine months ended September 30, 2014 were $4.24/mcf and $4.92 /mcf before hedge impact, which reduced natural gas price to $4.13/mcf and $4.46/mcf, respectively) generally correlate to the AECO daily index pricing, but may not always correlate to the AECO monthly index pricing. The reason for the variance is that in periods of rapid price increases or declines, a portion of the Company's sales, which are based mainly on the daily index, will not correlate to the monthly index.

At September 30, 2014, the Company held derivative commodity contracts aggregated as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	1,200 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $97.85
Crude oil	1,000 bbls/day	January 1, 2015 – March 31, 2015	WTI fixed price	Cdn $100.73
Crude oil	800 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $101.29
Crude oil	500 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	Cdn $101.72
Crude oil	300 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $101.50
Natural gas	1,000 GJ/day	October 1, 2014 – December 31, 2014	AECO fixed price	Cdn $4.30

These contracts as at September 30, 2014 had an unrealized gain of $139,704 that has been recorded on the balance sheet.

At September 30, 2014, the Company held physical commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Natural gas	4,000 GJ/day	October 1, 2014 – December 31, 2014	AECO fixed price	Cdn $3.70

Since September 30, 2014, the Company has entered into the following derivative commodity contract:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	100 bbls/day	November 1, 2014 – December 31, 2014	WTI fixed price	Cdn $99.10

Royalty expenses for the third quarter of 2014 were $8.87/boe or $4,701,831, representing 13% of revenue, compared to a royalty expense for the second quarter of 2014 of $8.87/boe or $4,201,055, representing 13% of revenue. Including the effect of the Wilson Creek Acquisition, the Company expects royalty rates to fluctuate between 12% and 15% depending on the number of new wells being drilled on Company owned lands with the initial Crown royalty incentive rate of 5% against wells drilled on farm-in wells that typically pay higher royalties.

The royalty expenses for the third quarter of 2013 were $7.33/boe or $2,131,804, representing 11% of revenue. The increase in royalties as a percentage of revenue in the third quarter of 2014, as compared to the third quarter of 2013, was related to the increase in the number of wells required to pay the freehold mineral tax as well as the effect of sliding scale royalty rates relating to higher gas prices.

Royalty expenses for the first nine months of 2014 were $8.60/boe or $11,862,719, representing 13% of revenue, compared to a royalty expense for the first nine months of 2013 of $6.85/boe or $5,459,756, representing 11% of revenue. The increase in royalties as a percentage of revenue in the first nine months of 2014, as compared to the same period in 2013, was related to the increase in the number of wells required to pay the freehold mineral tax as well as the effect of sliding scale royalty rates relating to higher gas prices.

Production Expenses

	Three months ended September 30,			Nine months ended September 30,		
	2014	2013	% change	**2014**	2013	% change
Gross costs	**$7,869,691**	$3,764,153	109	**$19,648,222**	$10,271,643	91
Total ($/boe)	**$14.84**	$12.94	15	**$14.24**	$12.89	10

Production expenses for the third quarter of 2014 were $14.84/boe compared to $14.35/boe incurred during the second quarter of 2014. Production expenses per boe were expected to trend higher in the third quarter due to the portion of heavy oil has increased from 1.7% to 7.2% of total production as there was a 91% increase to heavy oil production in the third quarter from the second quarter of 2014. The better than expected heavy oil production rate resulted in capacity restrictions at the 100% Company owned Hatton oil battery causing an increase to trucking costs. The Company has begun an oil battery expansion that is expected to be completed by the end of November 2014, thus operating costs are expected to decrease starting in December, 2014. The increase in per unit costs during the quarter was primarily the result of the Hatton battery constraint but other contributors include the increase in the higher cost oil production weighting (64% versus 61%) and planned work-overs during the third quarter. On a dollar basis, overall costs increased in the third quarter of 2014 by 16% to $7,869,691 from the $6,792,275 incurred during the second quarter of 2014. The increase in total production costs resulted from the 11% increase in production and the 15% increase to the per unit operating costs.

Production expenses on a boe basis were $14.84/boe in the third quarter of 2014 compared to $12.94/boe during the third quarter of 2013. Production expenses for the three months ended September 30, 2014 increased by 109% to $7,869,691, compared to $3,764,153 in the same period in 2013. The increase in total production costs, on a per boe basis, resulted from the increase in heavy oil production, the acquisition of the higher per unit cost Sure properties and planned work-overs during the third quarter of 2014. On a dollar basis, overall costs increased from an 82% increase in production and the increase in higher cost oil production weighting.

Production expenses on a boe basis were $14.24/boe in the first nine months of 2014 compared to $12.89/boe during the same period in 2013. Production expenses for the nine months ended September 30, 2014 increased by 91% to $19,648,222, compared to $10,271,643 in the same period in 2013. The increase in total production costs on a per boe basis resulted from the increase in heavy oil production, higher cost oil production weighting (61% versus 57%), the acquisition of the higher per unit cost Sure properties and planned work-overs during the second and third quarters of 2014. On a dollar basis, overall costs increased from a 73% increase in production and the increase in higher cost oil production weighting.

On September 30, 2014, the Company closed the Wilson Creek Acquisition, which included the acquisition of a 100% interest in a 3,800 bbl/d oil battery, a 52% interest in a 30 mmcf/d gas plant and various pipelines infrastructure spanning over five townships of land. The Company expects that operating costs per boe will trend lower in 2015, based on the effect of owning facility infrastructure on the Company's existing legacy production in the Wilson Creek area and the completion of the Hatton oil battery expansion.

Operating Netback

	Three months ended September 30,			Nine months ended September 30,		
($/boe)	**2014**	2013	% change	**2014**	2013	% change
Average realized sales	**66.62**	65.60	2	**66.77**	60.03	11
Royalty expenses	**(8.87)**	(7.33)	21	**(8.60)**	(6.85)	26
Production expenses	**(14.84)**	(12.94)	15	**(14.24)**	(12.89)	10
Operating field netback	**42.91**	45.33	(5)	**43.93**	40.29	9
Realized commodity hedging loss	**(2.03)**	(4.87)	(58)	**(2.95)**	(2.09)	41
Operating netback	**40.88**	40.46	1	**40.98**	38.20	7

The operating netback for the third quarter of 2014 decreased by 1% to $40.88/boe compared to $41.47/boe during the second quarter of 2014. The decrease was the result of a 5% decrease in oil and natural gas liquids prices ($90.19/bbl versus $94.65/bbl), a 5% decrease in natural gas prices ($4.13/mcf versus $4.37/mcf), a 3% increase in operating expense per boe ($14.84/boe versus $14.35/boe) and the portion of overall higher netback production related to liquids increasing (64% versus 61%), partially offset by a realized hedging loss of $2.03/boe during the third quarter 2014, compared to a $3.58/boe realized hedging loss during the second quarter of 2014.

The operating netback for the third quarter of 2014 increased by 1% to $40.88/boe compared to $40.46/boe during the third quarter of 2013. The increase was the result a 38% increase in natural gas prices ($4.13/mcf versus $2.99/mcf) and a realized hedging loss of $2.03/boe during the third quarter 2014 compared to a $4.87/boe realized hedging loss during the third quarter of 2013, partially offset by a 9% decrease in oil and natural gas liquids prices ($90.19/bbl versus $98.65/bbl), an increase of 21% in royalty expense per boe ($8.87/boe versus $7.33/boe) and a 15% increase in operating expense per boe ($14.84/boe versus $12.94/boe).

The operating netback for the first nine months of 2014 increased by 7% to $40.98/boe compared to $38.20/boe during the first nine months of 2013. The increase was the result of the portion of overall higher netback production related to liquids increasing (61% versus 57%), a 36% increase in natural gas prices ($4.46/mcf versus $3.28/mcf), a 3% increase in oil and natural gas liquids prices ($92.49/bbl versus $90.01/bbl), partially offset by a realized hedging loss of $2.95/boe during the first nine months of 2014 compared to a $2.09/boe realized hedging loss during same period in 2013, an increase of 26% in royalty expense per boe ($8.60/boe versus $6.85/boe) and a 10% increase in operating expense per boe ($14.24/boe versus $12.89/boe).

General and Administrative Expenses

	Three months ended September 30,			Nine months ended September 30,		
	2014	2013	% change	**2014**	2013	% change
Gross costs	**$2,178,671**	$1,286,514	69	**$5,805,576**	$3,870,146	50
Capitalized costs and recoveries	**(428,118)**	(298,204)	44	**(1,222,895)**	(958,896)	28
General and administrative costs	**$1,750,553**	$988,310	77	**$4,582,681**	$2,911,250	57
Total ($/boe)	**$3.30**	$3.40	(3)	**$3.32**	$3.65	(9)

General and administrative expenses for the third quarter of 2014 were $3.30/boe on costs of $1,750,553 compared to $3.19/boe on costs of $1,509,344 in the second quarter of 2014. The increased costs in the third quarter of 2014 were due to the full quarter effect of the staff additions in the second quarter of 2014 to manage Tamarack's growth. The increase in the cost per boe in the third quarter of 2014 was the result of an increase in the staffing costs, partially offset by an 11% increase in production.

General and administrative expenses for the third quarter of 2013 were $3.40/boe on costs of $988,310. The increased costs in the third quarter of 2014 were related to an 82% increase in production, an increase in the office lease and staffing costs.

General and administrative expenses for the first nine months of 2014 were $3.32/boe on costs of $4,582,681 compared to $3.65/boe on costs of $2,911,250 during the same period in 2013. The increased costs in the first nine months of 2014 were related to a 57% increase in production, an increase in the office lease and staffing costs. The decrease in the cost per boe during the first nine months of 2014 were related to a 57% increase in production, partially offset by an increase in the office lease and staffing costs.

Subsequent to the quarter and as a result of the Wilson Creek Acquisition, the Company added two full-time permanent field employees and three full-time office employees to its staff, bringing the total employee count to 19. Two of the three new full-time office staff additions had previously been part-time consultants with the Company for the past two years. The Company expects to add another one to two more full-time employees in the next three to six months.

Stock-based Compensation Expenses

Stock-based compensation expenses of $890,858 and $2,011,064, relating to the preferred shares, stock options and restricted share awards for the three and nine months ended September 30, 2014, was higher compared to $162,021 and $727,692 for the same periods in 2013, due to the issuance of new options and restrictive share awards in the third quarter of 2014. Stock-based compensation expense is calculated based on graded vesting periods that are front end loaded.

The Company capitalized $370,581 and $869,017 of stock-based compensation expenses relating to exploration and development activities for the three and nine months ended September 30, 2014, compared to capitalizing $106,674 and $365,071 for the same periods in 2013.

For the three and nine months ended September 30, 2014 the Company issued 466,000 and 1,031,000 options, respectively, at a weighted average exercise price of $6.82 and $5.63 per share.

The Company has a restricted share unit plan (the "RSU Plan") that allows the board of directors to grant restricted share awards to directors, officers and employees. Subject to terms and conditions of the RSU Plan, each restrictive share award entitles the holder to an award value to be paid as to one-third on each of the first, second and third anniversaries of the date of grant. For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. For the three and nine months ended September 30, 2014 the Company issued 411,000 restricted stock units.

For the three and nine months ended September 30, 2014, 206,250 preferred shares were exchanged for common shares at $3.12 per share and 35,499 and 123,498 stock options at $2.31 and $2.30 per share, respectively, were exercised for total gross proceeds of $927,441.

Interest

Interest expense, net of interest income, was $686,006 and $1,502,398 for the three and nine months ended September 30, 2014, compared to $525,572 and $1,444,591 for the same periods in 2013. The Company has drawn $100,274,534 on its revolving operating demand line at September 30, 2014, compared to $50,875,975 drawn on its line at September 30, 2013. Excluding the impact of the Wilson Creek Acquisition which closed on September 30, 2014 which resulted in a draw of $19 million on the Company's revolving operating demand line, the average amount drawn year-over-year was consistent thus resulting in similar interest expense.

Depletion, Depreciation, Amortization and Accretion

The Company depleted its property, plant, and equipment based on its proved plus probable reserves. The carrying value of undeveloped land in exploration and evaluation assets is also amortized over its term to expiry, which is charged to depletion, depreciation, and amortization expense.

	Three months ended September 30,			Nine months ended September 30,		
	2014	2013	% change	**2014**	2013	% change
Depletion and depreciation	**$11,195,137**	$5,414,474	107	**$28,220,277**	$14,852,831	90
Amortization of undeveloped leases	**813,738**	704,455	16	**2,378,068**	2,157,338	10
Accretion	**156,540**	74,041	111	**451,648**	219,894	105
Total	**$12,165,415**	$6,192,970	96	**$31,049,993**	$17,230,063	80
Depletion and depreciation ($/boe)	**$21.11**	$18.61	13	**$20.45**	$18.64	10
Amortization ($/boe)	**1.53**	2.42	(37)	**1.72**	2.71	(37)
Accretion ($/boe)	**0.30**	0.25	20	**0.33**	0.28	18
Total ($/boe)	**$22.94**	$21.28	8	**$22.50**	$21.63	4

Depletion, depreciation, amortization and accretion expense on a boe basis for the third quarter of 2014 was 1% higher at $22.94/boe, compared to $22.62/boe during the second quarter of 2014. Depletion, depreciation, amortization and accretion expense for the third quarter of 2014 was $12,165,415, compared to $10,704,398 during the second quarter of 2014. The 14% increase in total depletion, depreciation, amortization, and accretion expense was the result of the 11% increase in production and the higher per unit depletion, depreciation, amortization and accretion expense on a boe basis.

Depletion, depreciation, amortization, and accretion expense on a boe basis for the third quarter of 2014 was $22.94/boe, compared to $21.28/boe during the third quarter of 2013. Depletion, depreciation, amortization, and accretion expense for the third quarter of 2014 was $12,165,415, compared to $6,192,970 during the third quarter of 2013. The 96% increase in total depletion, depreciation, amortization, and accretion expense was the result of the 82% increase in production and the higher per unit depletion, depreciation and accretion expense on a boe basis.

Depletion, depreciation, amortization, and accretion expense on a boe basis for the first nine months of 2014 was $22.50/boe, compared to $21.63/boe during the first nine months of 2013. Depletion, depreciation, amortization, and accretion expense for the first nine months of 2014 was $31,049,993, compared to $17,230,063 during the first nine months of 2013. The 80% increase in total depletion, depreciation, amortization, and accretion expense was the result of the 73% increase in production and the higher 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 and nine months ended September 30, 2014, nor does it expect to pay any cash taxes in 2014 or in 2015 based on current commodity prices, forecast taxable income, existing tax pools, and planned capital expenditures.

For the three and nine months ended September, 2014, a deferred income tax expense of $2,557,428 and $5,275,236 was recognized, compared to a deferred income tax expense of $1,311,911 and $1,579,555 for the same periods in 2013. Deferred tax expense is higher in both periods due to increase in income before taxes.

As at September 30, 2014, the Company has recorded a deferred tax asset of $16,869,967.

Funds from Operations and Net Income

Funds from operations during the third quarter of 2014 were $15,808,881 ($0.26 per share basic and $0.25 per share diluted) compared to funds from operations of $17,789,622 ($0.29 per share basic and diluted) for the second quarter of 2014. The decrease in funds from operations is primarily the result of $3,441,352 in transaction costs incurred in completing the Wilson Creek Acquisition, which reduced funds from operations by $0.06 per share basic and $0.05 per share diluted.

Funds from operations during the three months ended September 30, 2014 were $15,808,881 ($0.26 per share basic and $0.25 per share diluted), compared to funds from operations of $10,259,964 ($0.35 per share basic and $0.34 per share diluted) for the same period in 2013. The increase in funds from operations is the result of increased production from the successful 2013 and 2014 drilling programs, the Sure Acquisition, a 38% increase in natural gas prices, partially offset by the transaction costs incurred completing the Wilson Creek Acquisition, higher operating and royalty expenses, higher realized hedging loss and a 9% decrease in oil and natural gas liquid prices.

Funds from operations during the first nine months of 2014 were $47,043,666 ($0.81 per share basic and $0.79 per share diluted), compared to funds from operations of $26,088,724 ($0.88 per share basic and diluted) for the same period in 2013. The increase in funds from operations is the result of increased production from the successful 2013 and 2014 drilling programs, the Sure Acquisition, a 36% increase in natural gas prices partially offset by the transaction costs incurred completing the Wilson Creek Acquisition, higher operating and royalty expenses and a higher realized hedging.

The Company had a net income of $6,790,587 ($0.11 per share basic and diluted) during the three months ended September 30, 2014, compared to a net income of $5,242,572 ($0.09 per share basic and $0.08 per share diluted) for the second quarter of 2014. The Company recorded a higher net income for the three months ended September 30, 2014 compared to the second quarter of 2014 as a result of a gain on a property disposition, a higher unrealized gain on financial instruments, partially offset by the transaction costs incurred completing the Wilson Creek Acquisition, decreased funds from operations, higher depletion, depreciation and amortization costs and higher deferred income tax expense.

The Company had net income of $6,790,587 ($0.11 per share basic and diluted) during the three months ended September 30, 2014, compared to net income of $3,721,097 ($0.13 per share basic and $0.12 per share diluted) for the same period in 2013. The Company recorded a higher net income for the three months ended September 30, 2014 as compared to the same period in 2013, due to increased funds from operations, a gain on a property disposition, partially offset by the transaction costs incurred completing the Wilson Creek Acquisition, higher depletion, depreciation and amortization costs and higher deferred income tax expense.

The Company had net income of $13,823,840 ($0.24 per share basic and $0.23 per share diluted) during the nine months ended September 30, 2014, compared to a net income of $3,958,358 ($0.13 per share basic and diluted) for the same period in 2013. The Company recorded a higher net income for the nine months ended September 30, 2014 as compared to the same period in 2013, due to increased funds from operations, a gain on a property disposition, an unrealized gain on financial instrument versus a loss, partially offset by the transaction costs incurred completing the Wilson Creek Acquisition, a higher depletion, depreciation and amortization costs and higher deferred income tax expense.

Capital Expenditures (including exploration and evaluation expenditures)

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

	Three months ended September 30,			Nine months ended September 30,		
	2014	2013	% change	**2014**	2013	% change
Land	**$217,579**	$744,025	(71)	**$2,940,187**	$3,070,536	(4)
Geological and geophysical	**393,529**	44,240	790	**684,966**	106,905	541
Drilling and completion	**27,416,874**	8,594,121	219	**80,509,114**	26,079,967	209
Equipment and facilities	**6,595,543**	1,248,086	428	**15,903,942**	5,997,657	165
Capitalized G&A	**(44,029)**	55,829	(179)	**641,655**	475,738	35
Office equipment	**7,929**	4,924	61	**45,729**	100,351	(54)
Total capital expenditures	**$34,587,425**	$10,691,225	224	**$100,725,593**	$35,831,154	181
Property acquisition	**166,056,562**	–	–	**166,056,562**	–	–
Proceeds from disposal of property, plant and equipment	**(4,269,237)**	–	–	**(4,653,090)**	(300,000)	1,451
Total net capital expenditures	**$196,374,750**	$10,691,225	1,737	**$262,129,065**	$35,531,154	638

During the third quarter of 2014, the Company completed and equipped 4 (2.3 net) horizontal Viking oil wells and 2 (1.85 net) horizontal Cardium wells, drilled, completed and equipped 3 (3.0 net) horizontal Cardium wells and 3 (3.0 net) heavy oil wells, including one potential injector. The Company also drilled and completed 4 (3.0 net) horizontal Cardium wells and spudded another 2 (1.5 net) horizontal Cardium wells in the Wilson Creek area. The Company decided to delay the tie-in and installation of permanent facilities for the 4 (3.0 net) wells until after the Wilson Creek Acquisition closed to save approximately $300,000 per well by being able to utilize the newly acquired pipelines and facility infrastructure.

2014 Drilling Summary (including wells spudded by September 30, 2014)		
	Gross	Net
Cardium	22.0	17.5
Viking	16.0	14.0
Heavy Oil	8.0	8.0
	46.0	39.5

For the three months ended September 30, 2014 the Company also disposed of its interest in a non-core property for $4,269,237, resulting in a gain on sale of $3,232,895. Production associated with this property was 61 boe/d at the time of the disposition.

The Company acquired 1,698 net acres of undeveloped lands in the Alder Flats area during the three months ended September 30, 2014. The Company's net undeveloped acreage was 218,754 acres at the end of the third quarter of 2014, including the 13,728 net acres acquired in the Wilson Creek Acquisition.

Liquidity and Capital Resources

Tamarack's net debt, including working capital deficiency excluding the fair value of financial instruments, was $121,684,316 at September 30, 2014. Tamarack's net debt at September 30, 2013, was $57,088,172. Due to closing the Wilson Creek Acquisition on the last day of the third quarter, Tamarack's net debt to annualized funds from operations in the third quarter was 1.9 times at September 30, 2014. This net debt to annualized funds from operations number does not take into account any funds from operations from the Wilson Creek Acquisition, but does include the increase to debt as a result of the Wilson Creek Acquisition that closed on September 30, 2014. The Company expects its net debt to annualized funds from operations in the fourth quarter to be less than 1.5 times. At September 30, 2013 the net debt to annualized funds from operations was 1.4 times.

On February 19, 2014, the Company completed a bought deal financing by issuing 14,000,000 common shares at $4.30 per share for total gross proceeds of $60,200,000 (the "February Offering"). The net proceeds of the financing were initially used to repay outstanding indebtedness and to fund the original $90 to 92 million capital budget for 2014 which was later increased. This drilling program focuses on accelerating horizontal Cardium oil development in the greater Pembina area and on the farm-in lands. Certain officers, directors of the Company and employees acquired 51,050 common shares as part of the February Offering for gross proceeds of $219,515.

On September 26, 2014, the Company completed a bought deal public offering of subscription receipts of the Company ("Subscription Receipts") and a bought deal private placement offering of common shares of the Company issued on a flow-through basis ("Flow-Through Shares") for aggregate gross proceeds of $125,163,000. The Company issued 16,100,000 Subscription Receipts at a price of $7.15 per Subscription Receipt, for gross proceeds of $115,115,000, and 1,280,000 Flow-Through Shares at a price of $7.85 per Flow-Through Share, for gross proceeds of $10,048,000. Certain officers, directors and employees of the Company acquired 49,000 Subscription Receipts for gross proceeds of $350,350. The gross proceeds from the sale of Subscription Receipts were held in escrow pending the completion of the Wilson Creek Acquisition, which closed on September 30, 2014, at which point such proceeds were released to Tamarack and each Subscription Receipt was exchanged for one common share of the Company.

During the nine months ended June 30, 2014, 206,250 preferred shares were exchanged for common shares at $3.12 per share and 123,498 stock options at $2.30 per share were exercised for total gross proceeds of $927,441.

At September 30, 2014, there were 77,878,466 common shares, 1,176,000 preferred shares, 4,005,386 options and 411,000 restricted share awards outstanding. At November 13, 2014, there were 77,928,466 common shares, 1,176,000 preferred shares, 4,147,386 options and 414,000 restricted share awards outstanding. At December 31, 2013 there were 46,168,718 common shares, 1,382,250 preferred shares and 3,164,551 options outstanding. The Company's weighted average basic common shares outstanding during the three and nine months ended September 30, 2014 were 61,423,738 and 58,140,697, respectively.

At September 30, 2014, the Company has a revolving credit facility in the amount of $140,000,000 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 30, 2015. If not extended, the facility will cease to revolve

and all outstanding balances will become repayable in one year from that extension date. 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 credit 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 credit facility has been secured by a $300,000,000 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 on November 30, 2014.

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

Although commodity price volatility continues in the oil and gas industry, Tamarack's strategy remains focused on the acquisition, development and production of petroleum and natural gas properties in western Canada. Subsequent to the equity financings completed in February and September, 2014, Tamarack has the flexibility with its current cash flow from operations and balance sheet to take advantage of opportunities that arise from an environment with commodity price volatility. Tamarack's net debt to annualized funds from operations is expected to decrease once a full quarter of cash flow from the Wilson Creek assets acquired are available.

Commitments

In the normal course of business, the Company has obligations which represent contracts and other commitments with an estimated payment of $169,952 for 2014, $720,121 for 2015, $436,044 for 2016 and $128,343 for 2017. These obligations are related to office lease commitments.

On September 26, 2014, the Company issued 1,280,000 flow-through common shares related to Canadian development expenditures for gross proceeds of $10,048,000. Under the terms of the flow-through share agreements, the Company is required to renounce and incur the $10,048,000 of qualifying oil and natural gas expenditures effective December 31, 2014. As of September 30, 2014 the Company has not incurred any of these expenditures.

The Company has also drilling and completion commitments related to the farm-in entered into on August 19, 2013. Overall 20 net wells must be drilled by December 31, 2016. As of June 30, 2014, the Company had satisfied approximately 39% of the drilling commitment. The Company estimates the capital expenditures to fulfill the remainder of this commitment will be approximately $39 to $46 million.

In conjunction with the Wilson Creek Acquisition, the Company is responsible for delivering 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 approximately four years.

2014/15 Guidance

On September 3, 2014 in conjunction with announcing the Wilson Creek Acquisition, the Company increased 2014 estimated exit production guidance by approximately 30% to 9,500 boe/d (approximately 60% oil & natural gas liquids) from the previously announced 7,300 to 7,500 boe/d range. At that time, there was uncertainty around the timing of the closing of the Wilson Creek Acquisition and as a result the Company did not update any other 2014 guidance numbers.

On September 3, 2014 the Company announced preliminary 2015 guidance that was based on an Edmonton par price average of $89.00/bbl and AECO price average of $3.57/GJ. Since that time Edmonton par prices have declined by 10 to 15%, causing the Company to re-evaluate its preliminary 2015 capital expenditure plan. Preserving a strong balance sheet will give Tamarack the flexibility to pursue opportunities in a low commodity price environment.

The Company will continue to execute the Wilson Creek area Q4 2014/Q1 2015 drilling program as previously disclosed and is targeting a first quarter 2015 plan to average at least 9,500 boe/d while reducing estimated net debt to annualized funds from operations to 1.3 times or less at current prices. The Company will release its 2015 guidance after finalizing its 2015 budget.

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 September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
Cash provided by operating activities	**$17,498,523**	$11,382,538	**$45,414,752**	$26,188,431
Abandonment expenditures	**136,739**	7,942	**411,907**	102,103
Changes in non-cash working capital	**(1,826,381)**	(1,130,516)	**1,217,007**	(201,810)
Funds from operations	**$15,808,881**	$10,259,964	**$47,043,666**	$26,088,724
Funds from operation per share -basic	**$ 0.26**	$ 0.35	**$ 0.81**	$ 0.88
Funds from operation per share -diluted	**$ 0.25**	$ 0.34	**$ 0.79**	$ 0.88

(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.

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

	September 30, 2014	December 31, 2013
Current assets	**$23,604,259**	$17,271,850
Current liabilities [1]	**(45,014,041)**	(71,795,945)
Bank debt	**(100,274,534)**	(27,240,060)
Net debt	**$(121,684,316)**	$(81,764,155)

(1) Excluding bank debt and the fair value of financial instruments.

Selected Quarterly Information

Three months ended	Sep. 30, 2014	Jun. 30, 2014	Mar. 31, 2014	Dec. 31, 2013	Sep. 30, 2013	Jun. 30, 2013	Mar. 31, 2013	Dec. 31, 2012
Sales volumes								
Natural gas *(mcf/d)*	**12,462**	12,033	11,093	10,349	7,767	7,125	7,496	7,505
Oil and NGL's *(bbls/d)*	**3,688**	3,197	2,333	2,611	1,867	1,702	1,452	1,310
Average boe/d *(6:1)*	**5,765**	5,203	4,182	4,336	3,162	2,890	2,701	2,561
Product prices								
Natural gas *($/mcf)*	**4.13**	4.37	4.93	3.72	2.99	3.61	3.25	3.26
Oil and NGL's *($/bbl)*	**90.19**	94.65	93.23	77.78	98.65	87.09	82.11	76.29
Oil equivalent *($/boe)*	**66.62**	68.27	65.09	55.72	65.60	60.21	53.16	48.57
(000s, except per share amounts)								
Financial results								
Gross revenues	**35,333**	32,322	24,498	22,224	19,082	15,830	12,923	11,445
Funds from operations	**15,809**	17,790	13,445	10,505	10,260	8,823	7,006	6,030
Per share – basic	**0.26**	0.29	0.26	0.24	0.35	0.30	0.24	0.20
Per share – diluted	**0.25**	0.29	0.25	0.23	0.34	0.30	0.24	0.20
Net income (loss)	**6,791**	5,243	1,791	10,855	3,721	(60)	297	(2,456)
Per share – basic	**0.11**	0.09	0.03	0.37	0.13	0.00	0.01	(0.08)
Per share – diluted	**0.11**	0.08	0.03	0.37	0.13	0.00	0.01	(0.08)
Additions to property and equipment, net of proceeds	**196,375**	40,742	25,012	22,010	10,691	13,057	11,783	11,873
Net property acquisitions	**166,057**	–	–	–	–	–	–	–
Corporate acquisitions	–	–	–	57,135	–	–	–	–
Total assets	**525,003**	319,065	288,608	269,707	170,610	168,090	159,496	152,344
Working capital (deficiency)[1]	**(21,270)**	(15,755)	(19,636)	(9,968)	(6,212)	(10,869)	(8,865)	(4,326)
Bank debt[2]	**100,275**	43,735	17,494	71,796	50,876	45,780	43,533	43,218
Decommissioning obligations	**36,732**	20,956	20,484	19,802	12,795	12,576	12,370	12,150
Deferred income tax (asset)	**(16,870)**	(17,743)	(19,681)	(19,467)	(8,717)	(10,029)	(10,102)	(10,296)

(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 effect this has had on revenue and net income (loss).
- The volatility in forward price curves affects the mark-to-market calculation which results in swings in earnings.
- On September 30, 2014, the Company acquired acquisition of 100% of Suncor Energy's interests in the Wilson Creek area of Alberta.
- Oil volumes have continued to grow due to successful drilling at Lochend, Garrington, Greater Pembina area and Redwater, and from the Sure and Echoex Ltd. ("Echoex") acquisitions. As a result, oil and natural gas liquids weighting has increased from 51% of total production in the fourth quarter of 2012 to 64% in the third quarter of 2014.
- On August 19, 2013, the Company entered into a farm-in agreement with an industry major to

earn 70% working interest in up to 113 net sections of prospective Cardium lands directly offsetting proven ongoing development projects in the greater Pembina area.

- On October 9, 2013 the Company acquired Sure; in 2013 this acquisition added $4,214,745 to oil and natural gas revenue and contributed $239,547 to net income.
- The Company recorded a $10,053,750 gain on the Sure acquisition for Q4 2013 as the fair value paid was less than the fair value of the assets acquired.
- The Company recorded $3,441,352 in transaction costs in the third 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 recorded impairment charges on the Company's natural gas related cash generating units ("CGU's") due to falling gas prices in the amount of $1,640,000 in the fourth quarter of 2012.

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.

Business Risks

Tamarack faces, or will face, 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.

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 "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "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 average and exit production rates in 2014.
- Estimated average first quarter 2015 production rate.
- Timing of the release of the Company's 2015 guidance and 2015 budget.
- Anticipated reductions in net debt in 2015.
- Tamarack's primary focus areas for production growth.
- Future drilling plans.
- Deferred tax liabilities.
- The interest rates under Tamarack's credit facilities.
- Future capital expenditures and capital program funding.
- Estimated general and administrative costs.
- Derivative contracts and Tamarack's commodity price and foreign exchange rate risk management activities.
- The timing and impact of implementing new accounting policies.
- The ability of the Company to continue to drill through the fourth quarter and to reduce costs by improving capital efficiencies.
- Expectations as to oil and natural gas weighting in 2014.
- Expectations as to royalty rates in 2014.

- The ability of the Company to take advantage of opportunities that may arise due to commodity price volatility.

With respect to the forward-looking statements contained in this MD&A, we have 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.

Also included in this MD&A are estimates of Tamarack's 2014 cash flow from operations and 2014 year end debt to annualized fourth quarter of 2014 cash flow from operations, which are based on the assumptions as to production levels, capital expenditures and commodity pricing disclosed in this MD&A. To the extent that such estimates constitute a financial outlook within the meaning of applicable securities laws, they were approved by management of Tamarack on September 3, 2014 and are included to provide readers with an understanding of Tamarack's anticipated cash flow based on the capital expenditure and other assumptions described herein. Readers are cautioned that the information may not be appropriate for other purposes. The actual results of Tamarack will likely vary from the amounts set forth in the financial outlook and such variation may be material. 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, 2013, which may be accessed on Tamarack's SEDAR profile at www.sedar.com.

The forward-looking statements contained in this MD&A are made as of the date hereof and Tamarack undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets
(unaudited)

	September 30, 2014	December 31, 2013
Assets		
Current assets:		
Accounts receivable	$23,128,008	$17,023,627
Prepaid expenses and deposits	476,251	248,223
Fair value of financial instruments (note 3)	139,704	–
	23,743,963	17,271,850
Property, plant and equipment (note 5)	470,971,976	221,311,760
Exploration and evaluation assets (note 6)	13,417,375	11,656,390
Deferred tax asset	16,869,967	19,466,879
	$525,003,281	$269,706,879
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$45,014,041	$27,240,060
Bank debt (note 11)	–	71,795,945
Fair value of financial instruments (note 3)	–	2,845,752
	45,014,041	101,881,757
Bank debt (note 11)	100,274,534	–
Decommissioning obligations (note 7)	36,732,185	19,801,991
Deferred flow-through share premium	896,000	–
Shareholders' equity:		
Share capital (note 10)	336,088,137	157,974,725
Contributed surplus	11,613,734	9,487,596
Deficit	(5,615,350)	(19,439,190)
	342,086,521	148,023,131
Commitments and contingencies (note 13)		
	$525,003,281	$269,706,879

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Income and Comprehensive Income
For the three and nine months ended September 30, 2014 and 2013
(unaudited)

	Three Months ended September 30,		Nine Months ended September 30,	
	2014	2013	2014	2013
Revenue:				
Oil and natural gas	$35,333,256	$19,082,189	$92,153,776	$47,834,836
Royalties	(4,701,831)	(2,131,804)	(11,862,719)	(5,459,756)
Realized loss on financial instruments (note 3)	(1,074,942)	(1,415,980)	(4,072,738)	(1,662,466)
Unrealized gain (loss) on financial instruments (note 3)	3,362,512	1,398,428	2,985,456	(2,469,244)
	32,918,995	16,932,833	79,203,775	38,243,370
Expenses:				
Production	7,869,691	3,764,153	19,648,222	10,271,643
General and administration	1,750,553	988,310	4,582,681	2,911,250
Transaction costs	3,441,352	–	3,441,352	–
Stock-based compensation	890,858	162,021	2,011,064	727,692
Finance	842,546	596,019	1,954,046	1,660,891
Depletion, depreciation and amortization	12,008,875	6,118,929	30,598,345	17,010,169
Gain on disposition of property, plant and equipment	(3,232,895)	–	(2,131,011)	(188,664)
Impairment of exploration and evaluation assets (note 6)	–	270,393	–	312,476
	23,570,980	11,899,825	60,104,699	32,705,457
Income before taxes	9,348,015	5,033,008	19,099,076	5,537,913
Deferred income tax expense	(2,557,428)	(1,311,911)	(5,275,236)	(1,579,555)
Net income and comprehensive income	$6,790,587	$3,721,097	$13,823,840	$3,958,358
Net income per share (note 9):				
Basic	$ 0.11	$ 0.13	$ 0.24	$ 0.13
Diluted	$ 0.11	$ 0.12	$ 0.23	$ 0.13

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Changes in Equity
(unaudited)

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders equity
Balance at January 1, 2013	29,706,752	$110,893,502	$7,795,213	$(34,252,316)	84,436,399
Shares issued on acquisition	16,461,966	47,081,223	–	–	47,081,223
Stock-based compensation	–	–	1,692,383	–	1,692,383
Net income	–	–	–	14,813,126	14,813,126
Balance at December 31, 2013	46,168,718	157,974,725	9,487,596	(19,439,190)	148,023,131
Issue of common shares	30,429,748	176,242,441	–	–	176,242,441
Issue of flow-through shares	1,280,000	10,048,000	–	–	10,048,000
Share issue costs, net of tax of $2,678,324	–	(8,034,972)	–	–	(8,034,972)
Transfer on exercise of stock options and warrants	–	753,943	(753,943)	–	–
Flow-through share premium	–	(896,000)	–	–	(896,000)
Stock-based compensation	–	–	2,880,081	–	2,880,081
Net income	–	–	–	13,823,840	13,823,840
Balance at September 30, 2014	77,878,466	$336,088,137	$11,613,734	$(5,615,350)	$342,086,521

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders equity
Balance at January 1, 2013	29,706,752	$110,893,502	$7,795,213	$(34,252,316)	$84,436,399
Stock-based compensation	–	–	1,092,763	–	1,092,763
Net income	–	–	–	3,958,358	3,958,358
Balance at September 30, 2013	29,706,752	$110,893,502	$8,887,976	$(30,293,958)	$89,487,520

See accompanying note to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Cash Flows
For the three and nine months ended September 30, 2014 and 2013
(unaudited)

	Three Months ended September 30,		Nine Months ended September 30,	
	2014	2013	2014	2013
Cash provided by (used in):				
Operating:				
Comprehensive income	$6,790,587	$3,721,097	$13,823,840	$3,958,358
Items not involving cash:				
Depletion, depreciation and amortization	12,008,875	6,118,929	30,598,345	17,010,169
Stock-based compensation	890,858	162,021	2,011,064	727,692
Gain on disposition of property, plant and equipment	(3,232,895)	–	(2,131,011)	(188,664)
Accretion expense on decommissioning obligations	156,540	74,041	451,648	219,894
Unrealized (gain) loss on financial instruments	(3,362,512)	(1,398,428)	(2,985,456)	2,469,244
Impairment of exploration and evaluation assets	–	270,393	–	312,476
Deferred income tax expense	2,557,428	1,311,911	5,275,236	1,579,555
Funds from operations	15,808,881	10,259,964	47,043,666	26,088,724
Abandonment expenditures (note 7)	(136,739)	(7,942)	(411,907)	(102,103)
Changes in non-cash working capital (note 8)	1,826,381	1,130,516	(1,217,007)	201,810
Cash provided by operating activities	17,498,523	11,382,538	45,414,752	26,188,431
Financing:				
Change in bank debt	56,540,023	5,096,368	28,478,589	7,658,037
Proceeds from issuance of common shares	125,245,036	–	186,290,441	–
Share issue costs	(6,737,091)	–	(10,713,296)	–
Cash provided by financing activities	175,047,968	5,096,368	204,055,734	7,658,037
Investing:				
Property, plant and equipment additions	(10,495,837)	(8,639,622)	(54,778,333)	(33,087,981)
Exploration and evaluation additions	(24,091,588)	(2,051,603)	(45,947,260)	(2,743,173)
Property acquisition (note 4)	(166,056,562)	–	(166,056,562)	–
Proceeds from disposal of property, plant and equipment	4,269,237	–	4,653,090	300,000
Changes in non-cash working capital (note 8)	3,828,259	(5,787,681)	12,658,579	1,684,686
Cash used in investing activities	(192,546,491)	(16,478,906)	(249,470,486)	(33,846,468)
Change in cash and cash equivalents	–	–	–	–
Cash and cash equivalents, beginning of period	–	–	–	–
Cash and cash equivalents, end of period	$ –	$ –	$ –	$ –

See accompanying notes to the condensed consolidated interim financial statements.

1. Reporting entity:

Tamarack Valley Energy Ltd. (the "Company") is incorporated under the Business Corporations Act of Alberta. The consolidated financial statements of the Company consist of the Company and its subsidiaries. The Company has the following wholly owned subsidiaries, all of which are incorporated in Canada: Tamarack Acquisition Corp., Tamarack Valley Holdings Corp. and Tamarack Valley Partnership. The Company is engaged in the exploration for, development and production of oil and natural gas.

Tamarack Valley Energy Ltd. is a publicly traded company, incorporated and domiciled in Canada. The address of its registered office is Suite 2500, 450 – 1st Street S.W., Calgary, Alberta, T2P 5H1. The address of its head office is currently 3100, 250 – 6th Avenue S.W., Calgary, Alberta T2P 3H7.

2. Basis of preparation:

(a) Statement of compliance:

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

These condensed consolidated interim financial statements have been prepared following the same accounting policies and methods of computation as the annual consolidated financial statements of the Company for the year ended December 31, 2013. The disclosures provided below are incremental to those included with the annual consolidated financial statements and certain disclosures, which are normally required to be included in the notes to the annual consolidated financial statements, have been condensed or omitted. These condensed consolidated interim financial statements should be read in conjunction with the consolidated financial statements and notes thereto in the Company's annual filings for the year ended December 31, 2013.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on November 13, 2014.

3. Commodity contracts:

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

All financial derivative contracts are classified as fair value through profit and loss and are recorded on the balance sheet at fair value. The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and level two published forward price curves as at the balance sheet date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates).

3. Commodity contracts (continued):

The fair value of options and collars is based on option models that use level two inputs, being published information with respect to volatility, prices and interest rates. The derivatives are valued at future value to profit and loss and therefore carrying amount equals future value.

At September 30, 2014, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value
Crude oil	100 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $95.50	($51,460)
Crude oil	200 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $92.00	($167,169)
Crude oil	200 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $93.00	($148,812)
Crude oil	200 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $94.00	($130,523)
Crude oil	200 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $110.00	$163,252
Crude oil	300 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $100.25	($23,588)
Crude oil	200 bbls/day	January 1, 2015 – March 31, 2015	WTI fixed price	Cdn $95.65	($76,055)
Crude oil	200 bbls/day	January 1, 2015 – March 31, 2015	WTI fixed price	Cdn $100.00	$27,580
Crude oil	200 bbls/day	January 1, 2015 – March 31, 2015	WTI fixed price	Cdn $107.00	$127,125
Crude oil	400 bbls/day	January 1, 2015 – March 31, 2015	WTI fixed price	Cdn $100.50	$21,533
Crude oil	100 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $104.80	$52,498
Crude oil	200 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $102.25	$58,985
Crude oil	200 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $100.50	$27,408
Crude oil	300 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $100.00	$1,816
Crude oil	200 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	Cdn $100.25	$33,429
Crude oil	300 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	Cdn $102.70	$116,961
Crude oil	300 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $101.50	$88,228
Natural gas	1,000 GJ/day	October 1, 2014 – December 31, 2014	AECO fixed price	Cdn $4.30	$18,496

These contracts as at September 30, 2014 had an unrealized gain of $139,704 that has been recorded on the balance sheet.

3. Commodity contracts (continued):

All physical commodity contracts are considered executory contracts and are not recorded at fair value on the balance sheet. On settlement the realized benefit or loss is recognized in oil and natural gas revenue. At September 30, 2014, the Company held physical commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Natural gas	4,000 GJ/day	October 1, 2014 – December 31, 2014	AECO fixed price	Cdn $3.70

Since September 30, 2014, the Company has entered into the following derivative commodity contracts:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	100 bbls/day	November 1, 2014 – December 31, 2014	WTI fixed price	Cdn $99.10

4. Property acquisition:

On September 30, 2014, the Company acquired certain working interests in developed petroleum and natural gas properties in the Wilson Creek area of Alberta for an aggregate cash purchase price of $168.5 million, prior to closing adjustments. The purpose of this acquisition was to increase the Company's exposure to the Cardium oil play. The operations from the acquisition have been included in the results of the Company commencing September 30, 2014. The Company incurred transaction costs of $3,441,352, which were expensed through the statement of income and comprehensive income.

The allocation of the purchase price is as follows:

Cash Consideration:		
Total consideration	$	166,056,562
Net Assets Acquired:		
Property, plant and equipment	$	171,797,498
Decommissioning obligations		(5,740,936)
Net assets	$	166,056,562

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

The fair value of property, plant and equipment has been determined with reference to a reserve report. The fair value of decommissioning obligations was initially estimated using a credit adjusted rate of 10%.

4. Property acquisitions (continued):

If the Wilson Creek properties had been acquired on January 1, 2014, the incremental oil and natural gas revenue and income recognized for the period ended September 30, 2014 and the pro forma results would have been as follows:

Period ended September 30, 2012	As stated	Wilson Creek Prior to acquisition	Pro Forma
Oil and natural gas revenue	$92,153,776	$30,255,319	$122,409,095
Net income	13,823,840	7,453,176	21,277,016

5. Property, plant and equipment:

	Oil and Natural gas Interests	Other Assets	Total
Cost:			
Balance at January 1, 2013	$154,102,756	$160,758	$154,263,514
Corporate acquisition	66,517,902	–	66,517,902
Cash additions	42,406,819	115,912	42,522,731
Decommissioning costs	408,387	–	408,387
Stock-based compensation	498,038	–	498,038
Transfer from exploration and evaluation assets	11,889,301	–	11,889,301
Disposals	(396,837)	–	(396,837)
Balance at December 31, 2013	275,426,366	276,670	275,703,036
Property acquisition	171,797,498	–	171,797,498
Cash additions	54,733,177	45,156	54,778,333
Decommissioning costs	11,538,186	–	11,538,186
Stock-based compensation	869,017	–	869,017
Transfer from exploration and evaluation assets	41,894,420	–	41,894,420
Disposals	(6,467,242)	–	(6,467,242)
Balance at September 30, 2014	$549,791,422	$321,826	$550,113,248
Depletion, depreciation and impairment losses:			
Balance at January 1, 2013	$31,359,644	$79,125	$31,438,769
Depletion and depreciation	22,336,138	42,038	22,378,176
Transfer from exploration and evaluation assets	267,038	–	267,038
Disposals	(178,707)	–	(178,707)
Impairment loss	486,000	–	486,000
Balance at December 31, 2013	54,270,113	121,163	54,391,276
Depletion and depreciation	28,179,872	40,405	28,220,277
Transfer from exploration and evaluation assets	86,213	–	86,213
Disposals	(3,556,494)	–	(3,556,494)
Balance at September 30, 2014	$78,979,704	$161,568	$79,141,272

	Oil and Natural gas Interests	Other Assets	Total
Carrying amounts:			
At December 31, 2013	$221,156,253	$155,507	$221,311,760
At September 30, 2014	$470,811,718	$160,258	$470,971,976

5. Property, plant and equipment (continued):

For the nine months ended September 30, 2014 the Company disposed of its interest in two non-core property for $4,653,090, resulting in a gain on sale of $2,131,011.

The calculation of depletion at September 30, 2014 includes estimated future development costs of $186,687,650 (December 31, 2013 – $203,235,000) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $20,530,000 (December 31, 2013 – $16,000,000).

6. Exploration and evaluation assets:

	Total
Cost:	
Balance at January 1, 2013	$23,385,606
Additions	15,318,324
Transfer to property, plant and equipment	(11,889,301)
Balance at December 31, 2013	26,814,629
Additions	45,947,260
Transfer to property, plant and equipment	(41,894,420)
Balance at September 30, 2014	$30,867,469
Amortization and impairment:	
Balance at January 1, 2013	$12,085,037
Amortization	2,866,677
Exploration and evaluation impairment	473,563
Transfer to property, plant and equipment	(267,038)
Balance at December 31, 2013	15,158,239
Amortization	2,378,068
Transfer to property, plant and equipment	(86,213)
Balance at September 30, 2014	$17,450,094

	Total
Carrying amounts:	
At December 31, 2013	$11,656,390
At September 30, 2014	$13,417,375

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, 2013 the Company recognized an impairment of $473,563 related to a recompletion attempt on a heavy oil well that was unsuccessful and a decision not drill a heavy well whose well site had been constructed.

7. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its decommissioning obligations to be approximately $41.6 million at September 30, 2014 (December 31, 2013 – $21.6 million), which is expected to be incurred between 2014 and 2038. A risk-free rate of 3.0% (2013 – 3.0%) and an inflation rate of 2% (2013 – 2%) is used to calculate the fair value of the decommissioning obligations at September 30, 2014 as presented in the table below:

	September 30, 2014	December 31, 2013
Balance, beginning of the period	**$19,801,991**	$12,149,514
Liabilities incurred	**1,958,335**	1,013,232
Liabilities acquired	**5,740,936**	7,107,113
Change in estimates	**–**	(604,845)
Change in discount rate on acquisition	**9,579,851**	–
Expenditures	**(411,907)**	(104,854)
Liabilities disposed	**(388,669)**	(106,794)
Accretion	**451,648**	348,625
Balance, end of the period	**$36,732,185**	$19,801,991

The decommissioning obligations acquired in the Wilson Creek Acquisition (note 4) were initially recognized using a fair value discount rate of 10%. They were subsequently revalued using the risk-free rate noted above resulting in the change in discount rate on acquisition in the above table with the offset to property, plant and equipment.

8. Supplemental cash flow information:

Changes in non-cash working capital consists of:

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
Source/(use of cash):				
Accounts receivable	**$(2,865,084)**	$725,909	**$(6,104,381)**	$(594,183)
Prepaid expenses and deposits	**(81,050)**	3,295	**(228,028)**	38,354
Accounts payable and accrued liabilities	**(36,413,267)**	(5,386,369)	**17,773,981**	2,442,325
	$(39,359,401)	$(4,657,165)	**$11,441,572**	$1,886,496
Related to operating activities	**$1,826,381**	$1,130,516	**$(1,217,007)**	$201,810
Related to investing activities	**3,828,259**	(5,787,681)	**$12,658,579**	$1,684,686

9. Income (loss) per share:

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

	Three months ended September 30,		Nine months ended September 30,	
	2014	2013	**2014**	2013
Net income for the period	**$6,790,587**	$3,721,097	**$13,823,840**	$3,958,358
Weighted average shares - basic	**61,423,738**	29,706,752	**58,140,697**	29,706,752
Weighted average shares - diluted	**63,509,567**	29,779,968	**59,872,353**	29,706,752
Net income per share-basic	**$ 0.11**	$ 0.13	**$ 0.24**	$ 0.13
Net income per share-diluted	**$ 0.11**	$ 0.12	**$ 0.23**	$ 0.13

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three and nine months ended September 30, 2014, 506,000 and 1,031,000 stock options, preferred shares and restrictive stock units, respectively, were excluded from the diluted earnings per share as they were anti-dilutive. For the three months ended September 30, 2013, 2,938,585 stock options and preferred shares were excluded from the diluted earnings per share as they were anti-dilutive. For the nine months ended September 30, 2013, no common shares were added to the basic weighted average number of common shares outstanding for the diluted effect of preferred shares and stock options, as they were anti-dilutive, and no adjustments to earnings were necessary.

10. Share capital:

On February 19, 2014, the Company completed a bought deal financing by issuing 14,000,000 common shares at $4.30 per share for total gross proceeds of $60,200,000. Certain officers, directors and employees acquired 51,050 common shares for gross proceeds of $219,515.

On September 26, 2014, the Company completed a bought deal financing by issuing 16,100,000 common shares at $7.15 per share for total gross proceeds of $115,115,000. Certain officers, directors and employees acquired 49,000 common shares for gross proceeds of $350,350.

On September 26, 2014, the Company issued 1,280,000 flow-through common shares, related to Canadian development expenditures, at $7.85 per share for total gross proceeds of $10,048,000.

During the nine months ended September 30, 2014, 206,250 preferred shares were exchanged into common shares at $3.12 per share and 123,498 stock options at $2.30 per share were exercised for total gross proceeds of $927,441.

11. Bank debt:

At September 30, 2014, the Company has a revolving credit facility in the amount of $140,000,000 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 30, 2015. If not extended, the facility will cease to revolve and all outstanding balances will become repayable in one year from that extension date. 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 credit 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 credit facility has been secured by a $300,000,000 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 on November 30, 2014.

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

At September 30, 2014, the Company had utilized the Facility in the amount of $100,274,534 and the Company was compliant with its working capital ratio at 1.6 to 1.0. The Facility replaces the previous $110 million demand facility and hence the classification has been changed from current to long-term to reflect the new terms.

As at September 30, 2014, the Company had letter of guarantees outstanding in the amount of $340,613 against the credit facility.

12. Share-based payments:

(a) Preferred share plan:

As at September 30, 2014 there are 1,176,000 (December 31, 2013 – 1,382,250) preferred shares outstanding with an exchange price of $3.12 per common share. During the nine months ended September 30, 2014 206,250 preferred shares were exchanged for common shares. The remaining contractual life is 0.8 years.

(b) Stock option plan:

Under the Company's stock option and restricted share unit plan it may grant up to 7,787,847 options or restricted share units to its employees, directors and consultants of which 5,009,116 options, preferred shares and restricted stock units have been issued that apply against this maximum amount. Stock options are granted at the market price of the shares at the date of grant, have a five-year term and vest one-third on each of the first, second and third anniversaries from the date of grant.

12. Share-based payments (continued):

(b) Stock option plan (continued):

The fair value of each option granted during the period was estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value and weighted average assumptions used to fair value the options are as follows:

	Nine months ended September 30, 2014	Year ended December 31, 2013
Risk free rate (%)	**1.37**	1.68
Expected volatility (%)	**80**	80
Expected life (years)	**5**	5
Forfeiture rate (%)	**–**	–
Dividend ($ per share)	**–**	–
Fair value at grant date ($ per option)	**3.67**	2.09

The number and weighted average exercise prices of stock option plan are as follows:

	Number of options	Weighted average exercise price
Outstanding, January 1, 2013	1,442,884	$ 2.67
Granted	1,730,000	3.15
Forfeited	(8,333)	4.80
Outstanding, December 31, 2013	3,164,551	$ 2.92
Granted	1,031,000	5.62
Exercised	(123,498)	2.30
Forfeited	(66,667)	2.39
Outstanding, September 30, 2014	**4,005,386**	**$ 3.65**

The following table summarizes information about stock options outstanding and exercisable at September 30, 2014:

	Options outstanding			Options exercisable	
Range of exercise price	Number outstanding	Weighted average exercise price	Weighted average remaining contractual life (years)	Number exercisable	Weighted average exercise price
$ 1.86 – 3.00	1,117,719	$2.12	3.0	669,270	$2.05
$ 3.01 – 5.00	2,421,667	$3.74	3.8	345,831	$4.46
$ 5.01 – 6.82	466,000	$6.82	4.9	–	–
$ 1.86 – 6.82	**4,005,386**	**$3.65**	**3.7**	**1,015,101**	**$2.87**

(c) Restricted stock unit plan

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

12. Share-based payments (continued):

(c) Restricted stock unit plan (continued):

For the purpose of calculating share-based compensation, the fair value of each award is determined at the grant date using the closing price of the common shares. The weighted average fair value of awards granted for the three and nine month periods ended September 30, 2014 was $6.93 per share award. On the date of exercise, the Company has the option of settling the award value in cash or in common shares of the Company.

The following table summarizes information about the restricted share awards at September 30, 2014:

	Number of options
Outstanding, December 31, 2013	–
Granted	**411,000**
Outstanding, September 30, 2014	**411,000**

13. Commitments and contingencies:

(a) Commitments

In the normal course of business, the Company has obligations which represent contracts and other commitments with an estimated payment of $169,952 for 2014, $720,121 for 2015, $436,044 for 2016 and $128,343 for 2017. These obligations are related to office lease commitments.

On September 26, 2014, the Company issued 1,280,000 flow-through common shares related to Canadian development expenditures for gross proceeds of $10,048,000. Under the terms of the flow-through share agreements, the Company is required to renounce and incur the $10,048,000 of qualifying oil and natural gas expenditures effective December 31, 2014. As of September 30, 2014 the Company has not incurred any of these expenditures.

The Company also has drilling and completion commitments related to its previously announced farm-in. Overall 20 net wells must be drilled by December 31, 2016. As of September 30, 2014, the Company has satisfied approximately 39% of the drilling commitment. The Company estimates the capital expenditures to fulfill the remainder of this commitment will be approximately $39 to $46 million.

In conjunction with the Wilson Creek Acquisition, the Company is responsible for delivering 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 approximately four years.

(b) Contingencies

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

CORPORATE INFORMATION

Directors

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

Dean Setoguchi[(1)(3)]

David Mackenzie[(1)(2)]

Jeff Boyce[(2)(3)]

Brian Schmidt

(1) Member of Audit Committee of the Board of Directors
(2) Member of the Reserves Committee of the Board of Directors
(3) Member of the Compensation & Governance Committee of the Board of Directors

Management Team

Brian Schmidt
President & Chief Executive Officer

Ron Hozjan
VP Finance & Chief Financial Officer

Dave Christensen
VP Engineering

Ken Cruikshank
VP Land

Kevin Screen
VP Production & Operations

Scott Reimond
VP Exploration

Noralee Bradley
Corporate Secretary

Banker

National Bank of Canada

Legal Counsel

Osler, Hoskin & Harcourt LLP

Auditor

KPMG LLP

Stock Exchange

TSX Venture Exchange

Stock symbol: TVE

Contact Information

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