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 six months ended June 30, 2014 and 2013. This MD&A is dated and based on information available on August 7, 2014 and should be read in conjunction with the unaudited condensed consolidated interim financial statements and notes for the three and six months ended June 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"). Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

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.

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 and the increased 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 and identify 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, and the shallow Viking oil play in Redwater and Westlock.

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 June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
Cash provided by operating activities	**$12,021,360**	$5,957,855	**$27,916,229**	$14,805,893
Abandonment expenditures	**235,991**	17,909	**275,168**	94,161
Changes in non-cash working capital	**5,532,271**	2,847,424	**3,043,388**	928,706
Funds from operations	**$17,789,622**	$8,823,188	**$31,234,785**	$15,828,760
Funds from operation per share -basic	**$ 0.29**	$ 0.30	**$ 0.55**	$ 0.53
Funds from operation per share -diluted	**$ 0.29**	$ 0.30	**$ 0.54**	$ 0.53

(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):

	June 30, 2014	December 31, 2013
Current assets	**$20,658,125**	$17,271,850
Current liabilities [1]	**(36,413,267)**	(27,240,060)
Bank debt	**(43,734,511)**	(71,795,945)
Net debt	**$(59,489,653)**	$(81,764,155)

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

Production

	Three months ended June 30,			Six months ended June 30,		
	2014	2013	% change	**2014**	2013	% change
Production						
Oil and natural gas liquids (bbls/d)	**3,197**	1,702	88	**2,768**	1,577	76
Natural gas (mcf/d)	**12,033**	7,125	69	**11,565**	7,310	58
Total (boe/d)	**5,203**	2,890	80	**4,696**	2,795	68
Percentage of oil and natural gas liquids	**61%**	59%		**59%**	56%	

Tamarack is pleased to report that it averaged 4,696 boe/d during the first half of 2014 in line with its guidance announced on January 28, 2014 of approximately 4,700 boe/d. The Company achieved this despite having 296 boe/d of production shut-in during the first six months due to facility curtailments and restrictions, unscheduled facility downtime and non-operated wells downtime

Production for the second quarter of 2014 increased by 24% to 5,203 boe/d from 4,182 boe/d in the first quarter of 2014, and increased by 80% from 2,890 boe/d in the second quarter of 2013. The 24% production increase during the second quarter of 2014, compared to the first quarter of 2014, was the result of 12 (11.7 net) new Viking oil wells coming on-stream during the quarter at Redwater adding 407 boe/d to the quarter average, 10 (7.3 net) new Cardium oil wells coming on-stream throughout the quarter in the Pembina, Wilson Creek and Harmattan areas, adding 912 boe/d to the quarter average and 4.0 net new heavy oil wells coming on-stream late in the quarter at Hatton adding 92 boe/d to the quarter average, offset by expected declines from existing production and from unscheduled facility downtime and curtailments which resulted in 296 boe/d of lost production.

Crude oil and natural gas liquids production in the second quarter of 2014 was 3,197 bbls/d compared to 2,333 bbls/d in the first quarter of 2014. Crude oil and natural gas liquids production increased 37% quarter-over-quarter as a result of 12 (11.7 net) new Viking oil wells coming on-stream during the quarter at Redwater adding 382 bbls/d to the quarter average, 10 (7.3 net) new Cardium oil wells coming on-stream throughout the quarter in the Pembina, Wilson Creek and Harmattan areas, adding 808 bbls/d to the quarter average and 4.0 net new heavy oil wells coming on-stream late in the quarter at Hatton adding 85 bbls/d to the quarter average, offset by expected declines from existing production and from unscheduled facility downtime and curtailments which resulted in 288 bbls/d of lost production. The percentage of oil and natural gas liquids weighting increased to 61% of total production in the second quarter of 2014 compared to 56% of total production during the first quarter of 2014. The Company expects its percentage of oil and natural gas liquids weighting to fluctuate between 55% and 62% dependant 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 12,033 mcf/d in the second quarter of 2014 compared to 11,093 mcf/d in the first quarter of 2014. Production increased quarter-over-quarter due to 12 (11.7 net) new Viking oil wells coming on-stream during the quarter at Redwater adding 148 mcf/d to the quarter average, 10 (7.3 net) new Cardium oil wells coming on-stream throughout the quarter in the Pembina, Wilson Creek and Harmattan areas, adding 626 mcf/d to the quarter average and 4.0 net new heavy oil wells coming on-stream late in the quarter at Hatton adding 44 mcf/d to the quarter average, offset by expected declines from existing production and from facility downtime and curtailments which resulted in 47 mcf/d of lost production.

Increases in production for the three and six months ended June 30, 2014, when compared to the same period in 2013, were due to production from the Sure Energy Inc. ("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 June 30,			Six months ended June 30,		
	2014	2013	% change	**2014**	2013	% change
Revenue						
Oil and NGLs	**$27,537,244**	$13,487,825	104	**$47,112,715**	$24,215,327	95
Natural gas	**4,785,021**	2,341,943	104	**9,707,805**	4,537,320	114
Total	**$32,322,265**	$15,829,768	104	**$56,820,520**	$28,752,647	98
Average realized price						
Oil and NGLs ($/bbl)	**94.65**	87.09	9	**94.05**	84.81	11
Natural gas ($/mcf)	**4.37**	3.61	21	**4.64**	3.43	35
Combined average ($/boe)	**68.27**	60.21	13	**66.86**	56.82	18
Benchmark pricing:						
Edmonton Par (Cdn$/bbl)	**104.13**	92.19	13	**101.86**	90.17	13
AECO daily index (Cdn$/mcf)	**4.67**	3.52	33	**5.17**	3.35	54
AECO monthly index (Cdn$/mcf)	**4.66**	3.58	30	**4.70**	3.32	42
Royalty expenses	**$4,201,055**	$1,878,438	124	**$7,160,888**	$3,327,952	115
$/boe	**8.87**	7.14	24	**8.43**	6.58	28
percent of sales	**13**	12	8	**13**	12	8

Revenue from crude oil, natural gas and associated natural gas liquids sales increased by 32% to $32,322,265 in the second quarter of 2014 from $24,498,255 in the first quarter of 2014 and increased by 104% as compared to $15,829,768 in the second quarter of 2013. Natural gas prices averaged $4.37/mcf and oil and natural gas liquids prices averaged $94.65/bbl in the second quarter of 2014 as compared to $4.93/mcf and $93.23/bbl in the first quarter of 2014 and compared to $3.61/mcf and $87.09/bbl in the second quarter of 2013, respectively.

The 32% increase in revenue during the second quarter of 2014, when compared to the first quarter of 2014, was primarily the result of the 37% increase in crude oil and natural gas liquids production, an 8% increase in natural gas production, and a 2% increase in crude oil and natural gas liquids pricing, partially offset by a 11% decrease in natural gas pricing.

The 104% increase to revenue in the second quarter of 2014, compared to the second quarter of 2013, was primarily caused by an 88% increase in crude oil and natural gas liquids production, a 69% increase in natural gas production, a 9% increase in crude oil and natural gas liquids pricing and a 21% increase in natural gas pricing.

The 98% increase to revenue in the first half of 2014, compared to the same period in 2013, was primarily caused by a 76% increase in crude oil and natural gas liquids production, a 58% increase in natural gas production, an 11% increase in crude oil and natural gas liquids pricing and a 35% increase in natural gas pricing.

The Company's realized crude oil and natural gas liquids prices for the three and six months ended June 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 six months ended June 30, 2014, excluding the impact of physical natural gas hedges (realized natural gas price for the three and six months ended June 30, 2014 were $5.05/mcf and $5.29 /mcf before hedge impact, which reduced natural gas price to $4.37/mcf and $4.64/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 June 30, 2014, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Crude oil	900 bbls/day	July 1, 2014 – September 30, 2014	WTI fixed price	Cdn $92.77
Crude oil	900 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $97.06
Crude oil	800 bbls/day	January 1, 2015 – March 31, 2015	WTI fixed price	Cdn $100.91
Crude oil	600 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $101.55
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 June 30, 2014 had an unrealized loss of $3,222,808 that has been recorded on the balance sheet.

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

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Natural gas	5,000 GJ/day	July 1, 2014 – September 30, 2014	AECO fixed price	Cdn $3.579
Natural gas	4,000 GJ/day	October 1, 2014 – December 31, 2014	AECO fixed price	Cdn $3.70

Royalty expenses for the second quarter of 2014 were $8.87/boe or $4,201,055, representing 13% of revenue, compared to a royalty expense for the first quarter of 2014 of $7.86/boe or $2,959,833, representing 12% of revenue. The increase in royalties as a percentage of revenue in the second quarter of 2014, as compared to the first quarter of 2014, was related to the payment of a Company gas cost allowance adjustment. The Company expects royalty rates to fluctuate between 10% and 12% dependant on the number of new wells being drilled on Company owned lands with the initial crown royalty incentive rate of 5%.

The royalty expenses for the second quarter of 2013 were $7.14/boe or $1,878,438, representing 12% of revenue. The increase in royalties as a percentage of revenue in the second quarter of 2014, as compared to the second 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 half of 2014 were $8.43/boe or $7,160,888, representing 13% of revenue, compared to a royalty expense for the first half of 2013 of $6.58/boe or $3,327,952, representing 12% of revenue. The increase in royalties as a percentage of revenue in the first half 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 June 30,			Six months ended June 30,		
	2014	2013	% change	**2014**	2013	% change
Gross costs	**$6,792,275**	$3,386,541	101	**$11,778,531**	$6,507,490	81
Total ($/boe)	**$14.35**	$12.88	11	**$13.86**	$12.86	8

Production expenses for the second quarter of 2014 were $14.35/boe compared to $13.25/boe incurred during the first quarter of 2014. The increase in per unit costs during the quarter was the result of the increase in the higher cost oil production weighting (61% versus 56%) and planned work-overs during the second quarter at Virginia Hills and Redwater, which added $0.55/boe to the period per unit costs and increased trucking costs associated with trucking partial loads during spring break-up. On a dollar basis, overall costs increased in the second quarter of 2014 by 36% to $6,792,275 from the $4,986,256 incurred during the first quarter of 2014. The increase in total production costs resulted from the 24% increase in production and the 8% increase to the per unit operating costs. Production expenses are expected to trend higher than originally expected in the third quarter due to the better than expected heavy oil production from the four net wells drilled in the second quarter. Long range plans to reduce heavy oil production expenses through an oil battery expansion are being considered.

Production expenses on a boe basis were $14.35/boe in the second quarter of 2014 compared to $12.88/boe during the second quarter of 2013. Production expenses for the three months ended June 30, 2014 increased by 101% to $6,792,275, compared to $3,386,541 in the same period in 2013. The increase in total production costs, on a per boe basis, resulted from the acquisition of the higher per unit cost Sure properties and planned work-overs during the second quarter of 2014 at Virginia Hills and Redwater. On a dollar basis, overall costs increased from an 80% increase in production and the increase in higher cost oil production weighting.

Production expenses on a boe basis were $13.86/boe in the first half of 2014 compared to $12.86/boe during the same period in 2013. Production expenses for the six months ended June 30, 2014 increased by 81% to $11,778,531, compared to $6,507,490 in the same period in 2013. The increase in total production costs on a per boe basis resulted from the increase in higher cost oil production weighting (59% versus 56%), the acquisition of the higher per unit cost Sure properties and planned work-overs during the second quarter of 2014 at Virginia Hills and Redwater. On a dollar basis, overall costs increased from a 68% increase in production and the increase in higher cost oil production weighting.

Operating Netback

	Three months ended June 30,			Six months ended June 30,		
($/boe)	**2014**	2013	% change	**2014**	2013	% change
Average realized sales	**68.27**	60.21	13	**66.86**	56.82	18
Royalty expenses	**(8.87)**	(7.14)	24	**(8.43)**	(6.58)	28
Production expenses	**(14.35)**	(12.88)	11	**(13.86)**	(12.86)	8
Operating field netback	**45.05**	40.19	12	**44.57**	37.38	19
Realized commodity hedging loss	**(3.58)**	(0.92)	291	**(3.53)**	(0.49)	620
Operating netback	**41.47**	39.27	6	**41.04**	36.89	11

The operating netback for the second quarter of 2014 increased by 2% to $41.47/boe compared to $40.52/boe during the first quarter of 2014. The increase was the result of a 2% increase in oil and natural gas liquids prices ($94.65/bbl versus $93.23/bbl) and of the portion of overall higher netback production related to liquids increasing (61% versus 56%), partially offset by a 11% decrease in natural gas prices ($4.37/mcf versus $4.93/mcf), an increase of 13% in royalty expense per boe ($8.87/boe versus $7.86/boe) and a 8% increase in operating expense per boe ($14.35/boe versus $13.25/boe).

The operating netback for the second quarter of 2014 increased by 6% to $41.47/boe compared to $39.27/boe during the second quarter of 2013. The increase was the result a 21% increase in natural gas prices ($4.37/mcf versus $3.61/mcf), a 9% increase in oil and natural gas liquids prices ($94.65/bbl versus $87.09/bbl), partially offset by a realized hedging loss of $3.58/boe during the second quarter 2014, compared to a $0.92/boe realized hedging loss during the second quarter of 2013, an increase of 24% in royalty expense per boe ($8.87/boe versus $7.14/boe) and a 11% increase in operating expense per boe ($14.35/boe versus $12.88/boe).

The operating netback for the first half of 2014 increased by 11% to $41.04/boe compared to $36.89/boe during the first half of 2013. The increase was the result of the portion of overall higher netback production related to liquids increasing (59% versus 56%), a 35% increase in natural gas prices ($4.64/mcf versus $3.43/mcf), a 11% increase in oil and natural gas liquids prices ($94.05/bbl versus $84.81/bbl), partially offset by a realized hedging loss of $3.53/boe during the first half of 2014, compared to a $0.49/boe realized hedging loss during same period in 2013, an increase of 28% in royalty expense per boe ($8.43/boe versus $6.58/boe) and a 8% increase in operating expense per boe ($13.86/boe versus $12.86/boe).

General and Administrative Expenses

	Three months ended June 30,			Six months ended June 30,		
	2014	2013	% change	**2014**	2013	% change
Gross costs	**$1,918,962**	$1,394,024	38	**$3,217,287**	$2,583,632	25
Capitalized costs and recoveries	**(409,618)**	(360,689)	14	**(385,159)**	(660,692)	(42)
General and administrative costs	**$1,509,344**	$1,033,335	46	**$2,832,128**	$1,922,940	47
Total ($/boe)	**$3.19**	$3.93	(19)	**$3.33**	$3.80	(12)

General and administrative expenses for the second quarter of 2014 were $3.19/boe on costs of $1,509,344 compared to $3.51/boe on costs of $1,322,784 in the first quarter of 2014. The increased costs in the second quarter of 2014 were related to an increase in staffing costs due to increasing full-time professionals to 13 from 10 at December 31, 2013. The decrease in the cost per boe in the second quarter of 2014 was the result of the 24% increase in production.

General and administrative expenses for the second quarter of 2013 were $3.93/boe on costs of $1,033,335. The increased costs in the second quarter of 2014 were related to an increase in the office lease and staffing costs. The decrease in the cost per boe in the second quarter of 2014 was the result of the 80% increase in production.

General and administrative expenses for the first half of 2014 were $3.33/boe on costs of $2,832,128 compared to $3.80/boe on costs of $1,922,940 during the same period in 2013. The increased costs in the first half of 2014 were related to an increase in the office lease and staffing costs. The decrease in the cost per boe in the first half of 2014 was the result of the 68% increase in production.

Stock-based Compensation Expenses

Stock-based compensation expenses of $582,404 and $1,120,206, relating to the preferred shares and stock options for the three and six months ended June 30, 2014, was higher compared to $280,373 and $565,671 for the same periods in 2013, due to the issuance of new options in the fourth quarter of 2013 and the first quarter of 2014. Stock-based compensation expense is calculated based on graded vesting periods that are front end loaded.

The Company capitalized $268,826 and $498,436 of stock-based compensation expenses relating to exploration and development activities for the three and six months ended June 30, 2014, compared to capitalizing $133,422 and $258,397 for the same periods in 2013.

For the three and six months ended June 30, 2014 the Company issued 565,000 options to three new employees at a weighted average exercise price of $4.64 per share.

For the three and six months ended June 30, 2014, 206,250 preferred shares were exchanged for common shares at $3.12 per share and 87,999 stock options at $2.29 per share were exercised for total gross proceeds of $845,405.

Interest

Interest expense, net of interest income, was $333,703 and $816,392 for the three and six months ended June 30, 2014, compared to $467,385 and $919,019 for the same periods in 2013. The Company has drawn $43,734,511 on its revolving operating demand line at June 30, 2014, compared to $45,779,607 drawn on its line at June 30, 2013. 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 June 30,			Six months ended June 30,		
	2014	2013	% change	**2014**	2013	% change
Depletion and depreciation	**$9,722,566**	$4,947,848	97	**$17,025,140**	$6,238,834	173
Amortization of undeveloped leases	**831,797**	727,537	14	**1,564,330**	4,652,406	(66)
Accretion	**150,035**	73,074	105	**295,108**	145,853	102
Total	**$10,704,398**	$5,748,459	86	**$18,884,578**	$11,037,093	71
Depletion and depreciation ($/boe)	**$20.54**	$18.82	9	**$20.03**	$12.33	62
Amortization ($/boe)	**1.76**	2.77	(36)	**1.84**	9.19	(80)
Accretion ($/boe)	**0.32**	0.28	14	**0.35**	0.29	21
Total ($/boe)	**$22.62**	$21.87	3	**$22.22**	$21.81	2

Depletion, depreciation, amortization and accretion expense on a boe basis for the second quarter of 2014 was 4% higher at $22.62/boe, compared to $21.74/boe during the first quarter of 2014. Depletion, depreciation, amortization and accretion expense for the second quarter of 2014 was $10,704,398, compared to $8,180,180 during the first quarter of 2014. The 31% increase in total depletion, depreciation, amortization, and accretion expense was the result of the 24% 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 second quarter of 2014 was $22.62/boe, compared to $21.87/boe during the second quarter of 2013. Depletion, depreciation, amortization, and accretion expense for the second quarter of 2014 was $10,704,398, compared to $5,748,459 during the second quarter of 2013. The 86% increase in total depletion, depreciation, amortization, and accretion expense was the result of the 80% 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 first half of 2014 was $22.22/boe, compared to $21.81/boe during the first half of 2013. Depletion, depreciation, amortization, and accretion expense for the first half of 2014 was $18,884,578, compared to $11,037,093 during the first half of 2013. The 71% increase in total depletion, depreciation, amortization, and accretion expense was the result of the 68% increase in production and the higher per unit depletion, depreciation, amortization and accretion expense on a boe basis.

Income Taxes

The Company did not incur any cash tax expense in the three and six months ended June 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 six months ended June, 2014, a deferred income tax expense of $1,941,647 and $2,717,808 was recognized, compared to a deferred income tax expense of $73,596 and $267,644 for the same periods in 2013. Deferred tax expense is higher in both periods due to increase in income before taxes.

As at June 30, 2014, the Company has recorded a deferred tax asset of $17,743,112.

Funds from Operations and Net Income

Funds from operations during the second quarter of 2014 were $17,789,622 ($0.29 per share basic and diluted) compared to funds from operations of $13,445,163 ($0.26 per share basic and $0.25 per share diluted) for the first quarter of 2014. The increase in funds from operations is the result of the 24% increase in production quarter-over-quarter, partially offset higher operating and royalty expenses.

Funds from operations during the three months ended June 30, 2014 were $17,789,622 ($0.29 per share basic and diluted), compared to funds from operations of $8,823,188 ($0.30 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 acquisition of Sure in third quarter of 2013, a 21% increase in natural gas prices and a 9% increase in oil and natural gas liquid prices.

Funds from operations during the first half of 2014 were $31,234,785 ($0.55 per share basic and $0.54 per share diluted), compared to funds from operations of $15,828,760 ($0.53 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 acquisition of Sure, a 35% increase in natural gas prices and an 11% increase in oil and natural gas liquid prices.

The Company had a net income of $5,242,572 ($0.09 per share basic and $0.08 per share diluted) during the three months ended June 30, 2014, compared to a net income of $1,790,681 ($0.03 per share basic and diluted) for the first quarter of 2014. The Company recorded a higher net income for the three months ended June 30, 2014 compared to the first quarter of 2014 due to a 24% increase in production quarter-over-quarter, an unrealized gain on financial instruments versus a loss in the first quarter, partially offset higher operating and royalty expenses, higher depletion, depreciation and amortization costs and higher deferred income tax expense.

The Company had net income of $5,242,572 ($0.09 per share basic and $0.08 per share diluted) during the three months ended June 30, 2014, compared to a net loss of $59,585 ($0.00 per share basic and diluted) for the same period in 2013. The Company recorded a higher net income for the three months ended June 30, 2014 as compared to the same period in 2013, due to increased funds from operations due to increased production, a 21% increase in natural gas prices, a 9% increase in oil and natural gas liquid prices, an unrealized gain on financial instrument versus a loss, partially offset by a higher realized loss on financial instruments, higher operating and royalty expenses, higher depletion, depreciation and amortization costs and higher deferred income tax expense.

The Company had net income of $7,033,253 ($0.12 per share basic and diluted) during the six months ended June 30, 2014, compared to a net income of $237,261 ($0.01 per share basic and diluted) for the same period in 2013. The Company recorded a higher net income for the six months ended June 30, 2014 as compared to the same period in 2013, due to increased funds from operations due to increased production, a 35% increase in natural gas prices, a 11% increase in oil and natural gas liquid prices, a lower unrealized loss on financial instrument, partially offset by a higher realized loss on financial instruments, higher operating and royalty expenses, 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 June 30,			Six months ended June 30,		
	2014	2013	% change	**2014**	2013	% change
Land	**$458,687**	$609,784	(25)	**$2,722,608**	$2,326,511	17
Geological and geophysical	**192,212**	15,452	1,144	**291,437**	62,665	365
Drilling and completion	**32,422,373**	10,388,546	212	**53,092,240**	17,485,846	204
Equipment and facilities	**7,279,260**	2,014,980	261	**9,308,399**	4,749,571	96
Capitalized G&A	**356,961**	279,849	28	**685,684**	419,909	63
Office equipment	**32,776**	48,020	(32)	**37,800**	95,427	(60)
Total capital expenditures	**$40,742,269**	$13,356,631	205	**$66,138,168**	$25,139,929	163
Proceeds from disposal of property, plant and equipment	**–**	(300,000)	–	**(383,853)**	(300,000)	28
Total net capital expenditures	**$40,742,269**	$13,056,631	212	**$65,754,315**	$24,839,929	165

During the second quarter of 2014, the Company finished drilling and completed and equipped two (1.88 net) horizontal Cardium farm-in wells that were spudded in the first quarter of 2014, completed and equipped 1 (0.88 net) 1.5-mile horizontal Cardium farm-in well, 5 (4.7 net) horizontal Viking oil wells, drilled, completed and equipped 2 (1.85 net) horizontal Cardium farm-in wells, 7 net horizontal Viking oil wells and 5 net heavy oil wells, including one injector. The Company also drilled 4 (2.3 net) horizontal Viking oil wells and spudded 2 (1.85 net) horizontal Cardium farm-in wells that were completed and equipped in July.

2014 Drilling Summary (including wells spudded by June 30, 2014)		
	Gross	Net
Cardium	13.0	10.0
Viking	16.0	14.0
Heavy Oil	5.0	5.0
	34.0	29.0

The Company acquired 3,822 net acres of undeveloped lands in the greater Pembina area during the three months ended June 30, 2014. The Company's net undeveloped acreage was 198,477 acres at the end of the second quarter of 2014.

Liquidity and Capital Resources

Tamarack's net debt, including working capital deficiency excluding the fair value of financial instruments, was $59,489,653 at June 30, 2014. Tamarack's net debt at June 30, 2013, was $56,648,969. Tamarack's net debt to annualized funds from operations in the second quarter was 0.84 times at June 30, 2014, compared to 1.61 times at June 30, 2013.

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 net proceeds of the financing were initially used to repay outstanding indebtedness and will fund the $90-92 million capital budget for 2014, focused on drilling Cardium horizontal and Viking oil horizontal development wells. This drilling program will focus on accelerating horizontal Cardium oil development in the greater Pembina area and on the Farm-in lands.

During the six months ended June 30, 2014, 206,250 preferred shares were exchanged for common shares at $3.12 per share and 87,999 stock options at $2.29 per share were exercised for total gross proceeds of $845,405.

At June 30, 2014 and August 7, 2014, there were 60,462,967 common shares, 1,176,000 preferred shares and 3,574,885 options 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 had 60,352,255 and 56,471,970 weighted average basic common shares outstanding during the three and six months ended June 30, 2014, respectively.

The Company had an operating demand line of credit in the amount of $90,000,000 and an $18,000,000 non-revolving acquisition/development demand line. The interest rate on the revolving operating demand line of credit was determined through a pricing grid that categorized based on a net debt to cash flow ratio. The interest rate will vary from a low of the bank's prime rate plus 0.5%, to a high of the bank’s prime rate plus 2.5% and the non-revolving acquisition/development demand line of credit will be an additional 0.5% over the applicable interest rate derived from the pricing grid. The credit facility was been secured by a $155,000,000 supplemental debenture with a floating charge over all assets.

On August 7, 2014, the Company executed a new credit facility with a syndicate of Canadian chartered banks. The new facility consists of a revolving credit facility in the amount of $100,000,000 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 original credit facility, the Company has provided a covenant that at the end of each quarter its working capital ratio shall not be less than 1.0 to 1.0. The working capital ratio is defined under the terms of the credit facilities as current assets, excluding derivative contracts, including the undrawn portion of the revolving operating demand line credit facility, to current liabilities, excluding any current bank indebtedness and derivative liabilities. As at June 30, 2014 the working capital ratio was 1.8 to 1.0 and the Company is in compliance with all covenants. A similar covenant will continue to exist under the Facility.

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 financing completed in February, 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.

Commitments

In the normal course of business, the Company has obligations which represent contracts and other commitments with an estimated payment of $339,183 for 2014, $720,121 for 2015, $436,044 for 2016 and $128,343 for 2017. These obligations are related to office lease commitments.

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.

Revised 2014 Guidance

On January 28, 2014, the Company disclosed production guidance for 2014. The 2014 production guidance is based on a capital program of $90-92 million that was set based on an average WTI price of $90.00/bbl Canadian with a $9.00 WTI / Edmonton Par differential and an average AECO price of $3.25/GJ. Highlights include:

- 2014 estimate average production rate of 5,300 to 5,500 boe/d (approximately 60% liquids)
- 2014 estimate exit production rate of between 6,500 to 6,700 boe/d (approximately 60% liquids)
- Estimated 2014 year end debt to annualized fourth quarter of 2014 cash flow from operation of less than 1.0 times

On August 11, 2014, Tamarack increased its 2014 capital expenditure program to $116 million which caused the following guidance revisions:

- 2014 estimate average production rate increased to 5,500 to 5,700 boe/d (approximately 59-61% liquids)
- 2014 estimate exit production rate of between 7,300 to 7,500 boe/d (approximately 58-61% liquids)
- 2014 estimate for cash flow from operations of between $74 to $77 million, assuming a second half 2014 Edmonton par price of $91.50/bbl and AECO average of $4.00/GJ
- Estimated 2014 year end debt to annualized fourth quarter of 2014 cash flow from operation of less than 0.9 times

Selected Quarterly Information

Three months ended	**Jun. 30, 2014**	Mar. 31, 2014	Dec. 31, 2013	Sep. 30, 2013	Jun. 30, 2013	Mar. 31, 2013	Dec. 31, 2012	Sep. 30, 2012
Sales volumes								
Natural gas *(mcf/d)*	**12,033**	11,093	10,349	7,767	7,125	7,496	7,505	8,074
Oil and NGL's *(bbls/d)*	**3,197**	2,333	2,611	1,867	1,702	1,452	1,310	1,311
Average boe/d *(6:1)*	**5,203**	4,182	4,336	3,162	2,890	2,701	2,561	2,657
Product prices								
Natural gas *($/mcf)*	**4.37**	4.93	3.72	2.99	3.61	3.25	3.26	2.34
Oil and NGL's *($/bbl)*	**94.65**	93.23	77.78	98.65	87.09	82.11	76.29	77.03
Oil equivalent *($/boe)*	**68.27**	65.09	55.72	65.60	60.21	53.16	48.57	45.12
(000s, except per share amounts)								
Financial results								
Gross revenues	**32,322**	24,498	22,224	19,082	15,830	12,923	11,445	11,028
Funds from operations	**17,790**	13,445	10,505	10,260	8,823	7,006	6,030	6,150
Per share – basic	**0.29**	0.26	0.24	0.35	0.30	0.24	0.20	0.21
Per share – diluted	**0.29**	0.25	0.23	0.34	0.30	0.24	0.20	0.21
Net income (loss)	**5,243**	1,791	10,855	3,721	(60)	297	(2,456)	(554)
Per share – basic	**0.09**	0.03	0.37	0.13	0.00	0.01	(0.08)	(0.02)
Per share – diluted	**0.08**	0.03	0.37	0.13	0.00	0.01	(0.08)	(0.02)
Additions to property and equipment, net of proceeds	**40,742**	25,012	22,010	10,691	13,057	11,783	11,873	7,194
Total assets	**319,065**	288,608	269,707	170,610	168,090	159,496	152,344	147,974
Working capital (deficiency)[1]	**(59,490)**	(37,130)	(81,764)	(57,088)	(56,649)	(52,398)	(47,544)	(41,547)
Decommissioning obligations	**20,956**	20,484	19,802	12,795	12,576	12,370	12,150	11,679
Deferred income tax (asset)	**(17,743)**	(19,681)	(19,467)	(8,717)	(10,029)	(10,102)	(10,296)	(9,997)

(1) Excluding fair value of financial instruments

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

- The volatility in commodity prices and the effect this has had on revenue and net income (loss).
- The volatility in forward price curves affects the mark-to-market calculation which results in swings in earnings.
- Oil volumes have continued to grow due to successful drilling at Lochend, Garrington, Greater Pembina area and Red Water, and from the Sure and Echoex Ltd. ("Echoex") acquisitions. As a result, oil and natural gas liquids weighting has increased from 49% of total production in the third quarter of 2012 to 61% in the second 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.
- On April 17, 2012 the Company acquired Echoex. In 2012, this acquisition added $9,468,534 to oil and natural gas revenue and contributed $1,388,110 to net income.
- The Company recorded $1,645,116 in transaction costs in the fourth quarter of 2013 related to the Sure acquisition and $1,065,190 in transaction costs related to the Echoex acquisition in the second and third quarters of 2012.
- 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.
- 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 second 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 use of proceeds from the Company's February 2014 bought deal financing.
- 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 which 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 August 11, 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.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Balance Sheets
(unaudited)

	June 30, 2014	December 31, 2013
Assets		
Current assets:		
Accounts receivable	$20,262,924	$17,023,627
Prepaid expenses and deposits	395,201	248,223
	20,658,125	17,271,850
Property, plant and equipment (note 4)	270,310,422	221,311,760
Exploration and evaluation assets (note 5)	10,352,943	11,656,390
Deferred tax asset	17,743,122	19,466,879
	$319,064,612	$269,706,879
Liabilities and Shareholders' Equity		
Current liabilities:		
Bank debt (note 10)	$43,734,511	$71,795,945
Accounts payable and accrued liabilities	36,413,267	27,240,060
Fair value of financial instruments (note 3)	3,222,808	2,845,752
	83,370,586	101,881,757
Decommissioning obligations (note 6)	20,955,749	19,801,991
Shareholders' equity:		
Share capital (note 9)	216,737,621	157,974,725
Contributed surplus	10,406,593	9,487,596
Deficit	(12,405,937)	(19,439,190)
	214,738,277	148,023,131
Commitments and contingencies (note 13)		
	$319,064,612	$269,706,879

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

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

	Three Months ended June 30,		Six Months ended June 30,	
	2014	2013	2014	2013
Revenue:				
Oil and natural gas	$32,322,265	$15,829,768	$56,820,520	$28,752,647
Royalties	(4,201,055)	(1,878,438)	(7,160,888)	(3,327,952)
Realized loss on financial instruments (note 3)	(1,696,266)	(240,881)	(2,997,796)	(246,486)
Unrealized gain (loss) on financial instruments (note 3)	681,399	(3,002,406)	(377,056)	(3,867,672)
	27,106,343	10,708,043	46,284,780	21,310,537
Expenses:				
Production	6,792,275	3,386,541	11,778,531	6,507,490
General and administration	1,509,344	1,033,335	2,832,128	1,922,940
Stock-based compensation	582,404	280,373	1,120,206	565,671
Finance	483,738	540,459	1,111,500	1,064,872
Depletion, depreciation and amortization	10,554,363	5,675,385	18,589,470	10,891,240
Loss (gain) on disposition of property, plant and equipment	–	(188,664)	1,101,884	(188,664)
Impairment of exploration and evaluation assets (note 5)	–	(33,397)	–	42,083
	19,922,124	10,694,032	36,533,719	20,805,632
Income before taxes	7,184,219	14,011	9,751,061	504,905
Deferred income tax expense	(1,941,647)	(73,596)	(2,717,808)	(267,644)
Comprehensive income (loss)	$5,242,572	$(59,585)	$7,033,253	$237,261
Net income (loss) per share (note 8):				
Basic	$ 0.09	$(0.00)	$ 0.12	$ 0.01
Diluted	$ 0.08	$(0.00)	$ 0.12	$ 0.01

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
Comprehensive 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	14,294,249	61,045,405	–	–	61,045,405
Share issue costs, net of tax of $994,051	–	(2,982,154)	–	–	(2,982,154)
Transfer on exercise of stock options and warrants	–	699,645	(699,645)	–	–
Stock-based compensation	–	–	1,618,642	–	1,618,642
Comprehensive income	–	–	–	7,033,253	7,033,253
Balance at June 30, 2014	60,462,967	$216,737,621	$10,406,593	$(12,405,937)	$214,738,277

	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	–	–	824,068	–	824,068
Comprehensive income	–	–	–	237,261	237,261
Balance at June 30, 2013	29,706,752	$110,893,502	$8,619,281	$(34,015,055)	$85,497,728

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 six months ended June 30, 2014 and 2013
(unaudited)

	Three Months ended June 30,		Six Months ended June 30,	
	2014	2013	2014	2013
Cash provided by (used in):				
Operating:				
Comprehensive income (loss)	$5,242,572	$(59,585)	$7,033,253	$237,261
Items not involving cash:				
Depletion, depreciation and amortization	10,554,363	5,675,385	18,589,470	10,891,240
Stock-based compensation	582,404	280,373	1,120,206	565,671
Loss (gain) on disposition of property, plant and equipment	–	(188,664)	1,101,884	(188,664)
Accretion expense on decommissioning obligations	150,035	73,074	295,108	145,853
Unrealized (gain) loss on financial instruments	(681,399)	3,002,406	377,056	3,867,672
Impairment of exploration and evaluation assets	–	(33,397)	–	42,083
Deferred income tax expense	1,941,647	73,596	2,717,808	267,644
Funds from operations	17,789,622	8,823,188	31,234,785	15,828,760
Abandonment expenditures (note 6)	(235,991)	(17,909)	(275,168)	(94,161)
Changes in non-cash working capital (note 7)	(5,532,271)	(2,847,424)	(3,043,388)	(928,706)
Cash provided by operating activities	12,021,360	5,957,855	27,916,229	14,805,893
Financing:				
Change in bank debt	26,240,983	2,246,787	(28,061,434)	2,561,669
Proceeds from issuance of common shares	845,405	–	61,045,405	–
Share issue costs	(16,124)	–	(3,976,205)	–
Cash provided by financing activities	27,070,264	2,246,787	29,007,766	2,561,669
Investing:				
Property, plant and equipment additions	(24,292,414)	(13,334,963)	(44,282,496)	(24,448,359)
Exploration and evaluation additions	(16,449,855)	(21,668)	(21,855,672)	(691,570)
Proceeds from disposal of property, plant and equipment	–	300,000	383,853	300,000
Changes in non-cash working capital (note 7)	1,650,645	4,851,989	8,830,320	7,472,367
Cash used in investing activities	(39,091,624)	(8,204,642)	(56,923,995)	(17,367,562)
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 are comprised 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 August 7, 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 June 30, 2014, the Company held derivative commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price	Fair value
Crude oil	200 bbls/day	July 1, 2014 – September 30, 2014	WTI fixed price	Cdn $91.00	($376,468)
Crude oil	200 bbls/day	July 1, 2014 – September 30, 2014	WTI fixed price	Cdn $95.15	($300,285)
Crude oil	200 bbls/day	July 1, 2014 – September 30, 2014	WTI fixed price	Cdn $100.00	($211,257)
Crude oil	300 bbls/day	July 1, 2014 – September 30, 2014	WTI fixed price	Cdn $87.55	($659,689)
Crude oil	100 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $95.50	($124,681)
Crude oil	200 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $92.00	($313,409)
Crude oil	200 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $93.00	($295,110)
Crude oil	200 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $94.00	($276,806)
Crude oil	200 bbls/day	October 1, 2014 – December 31, 2014	WTI fixed price	Cdn $110.00	$15,970
Crude oil	200 bbls/day	January 1, 2015 – March 31, 2015	WTI fixed price	Cdn $95.65	($200,453)
Crude oil	200 bbls/day	January 1, 2015 – March 31, 2015	WTI fixed price	Cdn $107.00	$2,081
Crude oil	400 bbls/day	January 1, 2015 – March 31, 2015	WTI fixed price	Cdn $100.50	($227,815)
Crude oil	100 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $104.80	($342)
Crude oil	200 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $102.25	($46,543)
Crude oil	300 bbls/day	April 1, 2015 – June 30, 2015	WTI fixed price	Cdn $100.00	($130,510)
Crude oil	200 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	Cdn $100.25	($52,588)
Crude oil	300 bbls/day	July 1, 2015 – September 30, 2015	WTI fixed price	Cdn $102.70	($12,299)
Crude oil	300 bbls/day	October 1, 2015 – December 31, 2015	WTI fixed price	Cdn $101.50	($11,193)
Natural gas	1,000 GJ/day	October 1, 2014 – December 31, 2014	AECO fixed price	Cdn $4.30	($1,413)

These contracts as at June 30, 2014 had an unrealized loss of $3,222,808 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 June 30, 2014, the Company held physical commodity contracts as follows:

Subject contract	Notional quantity	Remaining term	Hedge type	Strike price
Natural gas	5,000 GJ/day	July 1, 2014 – September 30, 2014	AECO fixed price	Cdn $3.579
Natural gas	4,000 GJ/day	October 1, 2014 – December 31, 2014	AECO fixed price	Cdn $3.70

4. 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
Cash additions	44,245,269	37,227	44,282,496
Decommissioning costs	1,236,412	–	1,236,412
Stock-based compensation	498,436	–	498,436
Transfer from exploration and evaluation assets	21,681,002	–	21,681,002
Disposals	(4,568,209)	–	(4,568,209)
Balance at June 30, 2014	$338,519,276	$313,897	$338,833,173
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	16,999,146	25,994	17,025,140
Transfer from exploration and evaluation assets	86,213	–	86,213
Disposals	(2,979,878)	–	(2,979,878)
Balance at June 30, 2014	$68,375,594	$147,157	$68,522,751

	Oil and Natural gas Interests	Other Assets	Total
Carrying amounts:			
At December 31, 2013	$221,156,253	$155,507	$221,311,760
At June 30, 2014	$270,143,682	$166,740	$270,310,422

4. Property, plant and equipment (continued):

For the six months ended June 30, 2014 the Company disposed of its interest in a non-core property for $383,853, resulting in a loss on sale of $1,101,884.

The calculation of depletion at June 30, 2014 includes estimated future development costs of $185,401,000 (December 31, 2013 – $203,235,000) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $18,635,000 (December 31, 2013 – $16,000,000).

5. 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	21,855,672
Transfer to property, plant and equipment	(21,681,002)
Balance at June 30, 2014	$26,989,299
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	1,564,330
Transfer to property, plant and equipment	(86,213)
Balance at June 30, 2014	$ 16,636,356

	Total
Carrying amounts:	
At December 31, 2013	$11,656,390
At June 30, 2014	$10,352,943

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.

6. Decommissioning obligations:

The decommissioning obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its decommissioning obligations to be approximately $22.9 million at June 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 June 30, 2014 as presented in the table below:

	June 30, 2014	December 31, 2013
Balance, beginning of the period	**$19,801,991**	$ 12,149,514
Liabilities incurred	**1,236,412**	1,013,232
Liabilities acquired	–	7,107,113
Revision	–	(604,845)
Expenditures	**(275,168)**	(104,854)
Liabilities disposed	**(102,594)**	(106,794)
Accretion	**295,108**	348,625
Balance, end of the period	**$20,955,749**	$19,801,991

7. Supplemental cash flow information:

Changes in non-cash working capital is comprised of:

	Three months ended June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
Source/(use of cash):				
Accounts receivable	**$(1,196,382)**	$(807,731)	**$(3,239,297)**	$(1,320,092)
Prepaid expenses and deposits	**(184,200)**	28,222	**(146,978)**	35,059
Accounts payable and accrued liabilities	**(2,501,044)**	2,784,074	**9,173,207**	7,828,694
Working capital deficiency on acquisition	**–**	–	**–**	–
	$(3,881,626)	$2,004,565	**$5,786,932**	$6,543,661
Related to operating activities	**$(5,532,271)**	$(2,847,424)	**$(3,043,388)**	$(928,706)
Related to investing activities	**1,650,645**	4,851,989	**$8,830,320**	$7,472,367

8. 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 June 30,		Six months ended June 30,	
	2014	2013	**2014**	2013
Net income (loss) for the period	**$5,242,572**	$(59,585)	**$7,033,253**	$237,261
Weighted average shares - basic	**60,352,255**	29,706,752	**56,471,970**	29,706,752
Weighted average shares - diluted	**62,079,457**	29,706,752	**57,910,218**	29,706,752
Net income (loss) per share-basic	**$ 0.09**	$(0.00)	**$ 0.12**	$ 0.01
Net income (loss) per share-diluted	**$ 0.08**	$(0.00)	**$ 0.12**	$ 0.01

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three and six months ended June 30, 2014, 565,000 stock options were excluded from the diluted earnings per share as they were anti-dilutive. For the three and six months June 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.

9. 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.

During the six months ended June 30, 2014, 206,250 preferred shares were exchanged into common shares at $3.12 per share and 87,999 stock options at $2.29 per share were exercised for total gross proceeds of $845,405.

10. Bank debt:

At June 30, 2014 the Company has a revolving operating demand line of $90,000,000 and an $18,000,000 non-revolving acquisition/development demand line with a Canadian chartered bank. The interest rate on the revolving operating demand line of credit 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 0.5% to a high of the bank’s prime rate plus 2.5% as derived from the pricing grid.

The standby fee for the operating demand line of credit will vary as per the pricing grid from a low of 0.2% to a high of 0.45% on the undrawn portion of the credit facilities. The facility is secured by a $155,000,000 debenture with a floating charge over all assets.

10. Bank debt (continued):

On August 7, 2014, the Company executed a new credit facility with a syndicate of Canadian chartered banks. The new facility consists of a revolving credit facility in the amount of $100,000,000 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 original 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 revolving operating demand line credit facility, to current liabilities, excluding any current bank indebtedness and derivative liabilities. A similar covenant will continue to exist under the new facility.

At June 30, 2014, the Company had utilized the revolving operating demand line of credit in the amount of $43,734,511 and the Company was compliant with its working capital ratio at 1.8 to 1.0.

As at June 30, 2014, the Company had letter of guarantees outstanding in the amount of $418,612 against the credit facility.

11. Share-based payments:

(a) Preferred share plan:

As at June 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 period ended June 30, 2014, 206,250 preferred shares were exchanged for common shares. The remaining contractual life is 1.0 year.

(b) Stock option and restricted share unit plan:

Under the Company's stock option and restricted share unit plan it may grant up to 6,046,297 options or restricted share units to its employees, directors and consultants of which 4,271,570 options and preferred shares have been issued that apply against this maximum amount. No restricted share units have been issued. 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.

11. 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:

	Three months ended June 30, 2014	Year ended December 31, 2013
Risk free rate (%)	**1.33**	1.68
Expected volatility (%)	**80**	80
Expected life (years)	**5**	5
Forfeiture rate (%)	**–**	–
Dividend ($ per share)	**–**	–
Fair value at grant date ($ per option)	**3.01**	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	565,000	4.64
Exercised	(87,999)	2.29
Forfeited	(66,667)	2.39
Outstanding, June 30, 2014	**3,574,885**	**$ 3.22**

(b) Stock option plan (continued):

The following table summarizes information about stock options outstanding and exercisable at June 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 – 2.70	1,104,052	$2.08	3.2	330,462	$2.09
$ 2.90 – 5.00	2,470,833	$3.73	4.0	266,386	$4.34
$ 1.86 – 5.00	**3,574,885**	**$3.22**	**3.8**	**596,848**	**$3.09**

12. 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 $339,183 for 2014, $720,121 for 2015, $436,044 for 2016 and $128,343 for 2017. These obligations are related to office lease commitments.

The Company also has drilling and completion commitments related to its recently announced Farm-in. Overall 20 net wells must be drilled by December 31, 2016. As of June 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.

(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

Toronto Venture Exchange TVE

Contact Information

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