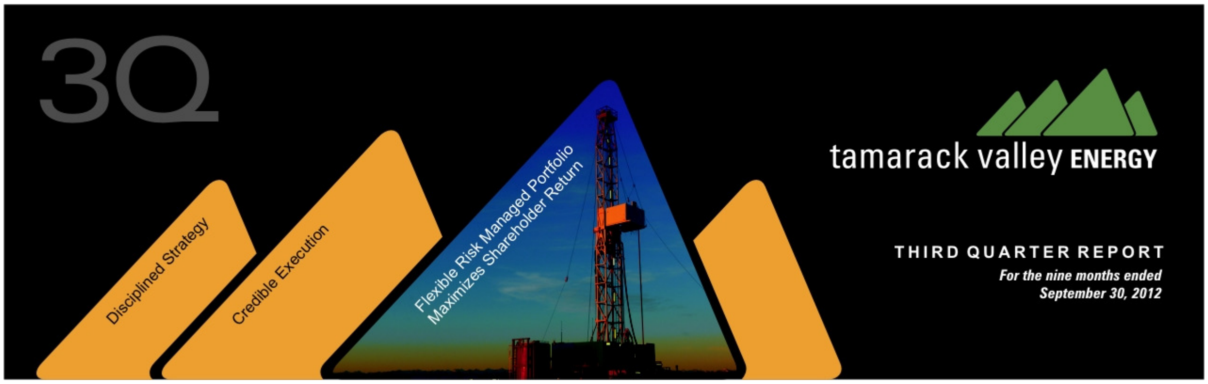

TAMARACK VALLEY ENERGY LTD.

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, 2012 and 2011. This MD&A is dated and based on information available at November 13, 2012 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, 2012 and 2011 and with the audited consolidated financial statements and notes for the years ended December 31, 2011 and 2010. Additional information relating to Tamarack, including Tamarack's annual information form, is available on SEDAR at www.sedar.com

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Unless otherwise indicated, all references to dollar amounts are in Canadian currency.

On July 16, 2012 the Company consolidated its common shares on a 1 for 12 basis and all number of shares and per share amounts have been restated to reflect the consolidation.

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's may be misleading, particularly if used in isolation.

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 are therefore unlikely to be comparable to similar measures presented by other issuers. The Company uses net debt (bank indebtedness plus negative working capital or less positive working capital) 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.

(a) **Funds from Operations -** Tamarack's method of calculating funds from operations may differ from other companies, and accordingly it 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 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,	
	2012	2011	**2012**	2011
Cash provided by operating activities	**$6,408,722**	$4,999,961	**$10,047,012**	$6,020,336
Abandonment expenditures	**9,037**	10,783	**81,554**	22,095
Changes in non-cash working capital	**(267,355)**	(1,968,622)	**508,575**	(107,300)
Funds from operations	**$6,150,404**	$3,042,122	**$10,637,141**	$5,935,131
Funds from operation per share -basic	**$ 0.21**	$ 0.20	**$ 0.43**	$ 0.41
Funds from operation per share -diluted	**$ 0.21**	$ 0.20	**$ 0.43**	$ 0.41

(b) **Operating Netback -** Management uses certain industry benchmarks such as operating netback to analyze financial and operating performance. This benchmark as presented 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, 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 8 in the section titled "Operating Netback".

(c) **Net Debt -** The Company closely monitors its capital structure with a goal of maintaining a strong balance sheet in order 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 tables outline the Company's calculation of net debt (excluding the effect of derivative contracts):

	September 30, 2012	December 31, 2011
Current Assets	**$7,352,497**	$2,847,603
Current liabilities	**(11,027,006)**	(9,434,535)
Bank debt	**(37,966,373)**	(1,027,231)
Net debt	**(41,640,882)**	(7,614,163)

About Tamarack

Tamarack is a Calgary based, oil and natural gas company focused on delivering a superior rate of return on capital investment. We utilize a proven, rigorous process to identify opportunities, evaluate risk and measure results. We employ a specific resource play screening criteria to identify and evaluate prospective areas for repeatability, scope, large original oil or gas-in-place per section, which usually suggests sizeable reserves, and long life opportunities. Our strategy involves the identification and development of assets in four different core areas. To date we have established oil prospective lands in Lochend and Garrington (Cardium oil), Buck Lake (Cardium oil and natural gas), Redwater (shallow Viking oil play) and Saskatchewan heavy oil.

Acquisition

On April 17, 2012, the Company acquired all of the issued and outstanding shares of Echoex Ltd. ("Echoex"), a Canadian private oil and gas company (the "Acquisition"). As consideration, Echoex shareholders received an aggregate of $10,000,000 of cash and 7,810,722 Tamarack common shares with an ascribed value on the date of closing of $2.52 per common share. Upon completion of the Acquisition, Echoex became a wholly owned subsidiary of Tamarack under the name "Echoex Ltd.". Concurrent with the closing of the Echoex acquisition on April 17, 2012, the Company received proceeds on the issue of 5,500,000 subscription receipts at a price of $3.00 per subscription receipt for gross proceeds of $16,500,000 pursuant to a bought deal financing announced on March 26, 2012. An aggregate of 5,500,000 common shares were issued to holders of subscription receipts upon closing of the Acquisition. In addition, the Company incurred transaction costs of $1,065,190, which were expensed through the statement of comprehensive loss.

Echoex has a material position in the Redwater area of Alberta, Canada and along the Redwater Viking Trend where the majority of its production and reserves are focused in the economic shallow Viking oil formation. Echoex's two primary Viking oil properties, Redwater and Westlock, are on trend with Tamarack's existing shallow Viking oil play in Foley Lake and have significant growth and upside potential with over 60 horizontal Viking drilling locations. The Acquisition represents the continuation of Tamarack's disciplined business plan to build an inventory of high quality light oil assets that can provide significant development upside to complement the Corporation's existing oil-focused plays. Tamarack will apply its expertise, developing horizontal oil resource plays, to its newly expanded shallow Viking oil position along the Redwater Viking Trend.

Production

	Three months ended September 30,			Nine months ended September 30,		
	2012	2011	% change	**2012**	2011	% change
Production						
Oil and natural gas liquids (bbls/d)	**1,311**	460	185	**877**	271	224
Natural gas (mcf/d)	**8,074**	3,849	110	**6,935**	3,900	78
Total (boe/d)	**2,657**	1,102	141	**2,033**	921	121
Percentage of oil and natural gas liquids	**49%**	42%		**43%**	29%	

Production for the third quarter of 2012 increased by 21% to 2,657 boe/d from 2,193 boe/d in the second quarter of 2012, and by 141% from 1,102 boe/d in the third quarter of 2011. Production increased during the third quarter of 2012 compared to the second quarter of 2012 as a result of a full quarter of production from the acquired Echoex properties adding an additional 203 boe/d (third quarter – 922 boe/d versus second quarter – 719 boe/d) from the second quarter, the four new wells (3.7 net wells) in Redwater producing for a full quarter adding an additional 190 boe/d (third quarter – 266 boe/d versus second quarter – 76 boe/d) from the second quarter, two (1.1 net wells) wells coming on-stream in Garrington during August adding 235 boe/d to the quarter average and two (1.0 net wells) wells in Lochend coming on-stream at the end of September adding 30 boe/d to the quarter average. These production additions offset the expected declines from base production.

Tamarack's 2012 production guidance, disclosed on April 19, 2012, assumed the Company would average 2,464 boe/d in the third quarter of 2012 compared to the actual production of 2,657 boe/d. The increase versus guidance was due in part to achieving better than expected drilling results and Tamarack's ability to bring new production on-stream faster than originally anticipated. The Company is on track to be in the upper half of its 2012 average production guidance of 2,000 to 2,200 boe/d and expects to meet its 2012 exit production rate of 2,600 to 2,700 boe/d.

Crude oil and natural gas liquids production increased by 43% to 1,311 bbls/d compared to 914 bbls/d in the second quarter of 2012. This increase was again reflective of a full quarter of production from the acquired Echoex properties adding an additional 97 bbls/d (third quarter – 411 bbls/d versus second quarter – 314 bbls/d) from the second quarter, the four new wells (3.7 net wells) in Redwater producing for a full quarter adding an additional 190 bbls/d (third quarter – 266 bbls/d versus second quarter – 76 bbls/d) from the second quarter, two (1.1 net wells) wells coming on-stream in Garrington during August adding 201 bbls/d to the quarter average and two (1.0 net wells) wells in Lochend coming on-stream at the end of September adding 30 bbls/d to the quarter average. These oil production additions offset the expected declines from base production. The percentage of oil and natural gas liquids weighting increased to 49% of total production in the third quarter of 2012 compared to 42% of total production in the second quarter of 2012.

Increases in production for the three months ended September 30, 2012 when compared to 2011 were primarily due to the 2012 drilling program which included three (2.0 net wells) Cardium oil wells in Lochend, two (1.1 net wells) Cardium oil wells in Garrington, one 75% working interest Cardium well at Buck Lake and four (3.7 net wells) Viking oil wells in Redwater, along with the completion of the Echoex acquisition on April 17, 2012. Increases in production during the first nine months of 2012 when compared to 2011 were primarily due to the Echoex acquisition, the successful 2012 drilling of a well (0.75 net) at Buck Lake, three (2.0 net) wells at Lochend, three (1.6 net wells) Cardium oil wells in Garrington, four (3.7 net wells) Viking oil wells in Redwater, and drilling that occurred in the second half of 2011.

Petroleum, Natural Gas Sales and Royalties

	Three months ended September 30,			Nine months ended September 30,		
	2012	2011	% change	**2012**	2011	% change
Revenue						
Oil and NGLs	**$9,293,709**	$3,866,307	140	**$18,858,985**	$6,800,387	177
Natural gas	**1,734,671**	1,356,114	28	**4,109,306**	4,179,670	(2)
Total	**$11,028,380**	$5,222,421	111	**$22,968,291**	$10,980,057	109
Average Realized price						
Oil and NGLs ($/bbl)	**77.03**	91.38	(16)	**78.50**	**91.97**	(15)
Natural gas ($/mcf)	**2.34**	3.83	(39)	**2.16**	3.93	(45)
Combined Average ($/boe)	**45.12**	51.54	(12)	**41.24**	43.68	(6)
Benchmark pricing:						
Edmonton Par (Cdn$/bbl)	**84.22**	91.77	(8)	**86.78**	94.26	(8)
AECO monthly index (Cdn$/mcf)	**2.18**	3.70	(41)	**1.97**	3.76	(48)
Royalty Expenses	**$1,096,844**	$417,793	163	**$1,660,478**	$351,560	372
$/boe	**4.49**	4.12	9	**2.98**	1.40	113
percent of sales	**10**	8	25	**7**	3	133

Revenue from crude oil, natural gas and associated natural gas liquids sales increased by 40% to $11,028,380 in the third quarter of 2012 from $7,857,023 in the second quarter of 2012 and increased by 111% as compared to the third quarter in 2011 ($11,028,380 versus $5,222,421). Natural gas prices averaged $2.34/mcf and oil and natural gas liquids prices averaged $77.03/bbl in the third quarter of 2012 as compared to $1.94/mcf and $78.19/bbl in the second quarter of 2012 and compared to $3.83/mcf and $91.38/bbl in the third quarter of 2011, respectively. The 40% increase in revenue during the third quarter of 2012 when compared to the second quarter of 2012 was primarily the result of the 43% increase in crude oil and natural gas liquids production.

The 111% increase to revenue in the third quarter of 2012 compared to the same period in 2011 was primarily caused by the 141% increase in production, an increase in the portion of overall production related to liquids (49% vs. 42%), partially offset by a 16% decrease to oil and natural gas liquids prices and a 39% decrease to natural gas prices.

The 109% increase to revenue in the first nine months of 2012 compared to the same period in 2011 was primarily caused by the 121% increase in production, an increase in the portion of overall production related to liquids (43% vs. 29%), partially offset by a 15% decrease to oil and natural gas liquids prices and a 45% decrease to natural gas prices.

The Company's realized crude oil and natural gas liquids prices for the three and nine months ended September 30, 2012 and 2011 generally correlate to the Edmonton Par Canadian price posting for the same period, however, the discount the Company is receiving is the result of quality adjustments and the effect of selling a greater portion of total production to pool price contracts versus direct sales contracts. Direct sales contracts relate to oil that is sold directly in Alberta and is not subject to the pipeline constraints which is putting downward pressure on the pool price contracts. The Company markets as much oil as possible into the direct sales contracts but is restricted by how much oil these contracts can absorb. The natural gas liquids are priced at varying discounts to Edmonton Par pricing 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, 2012 compared to the same periods ended in 2011 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 declines or increases a portion of the Company's sales, which are based on a daily index, will not correlate to the monthly index.

At September 30, 2012, the Company held derivative commodity contracts as follows:

Subject Contract	Notional Quantity	Term	Hedge Type	Strike Price
Natural Gas	800 GJ/day	August 1, 2012 – December 31, 2012	AECO fixed price swap	Cdn $2.45
Natural Gas	2,000 GJ/day	April 1, 2012 – December 31, 2012	AECO fixed price swap	Cdn $2.37
Natural Gas	1,500 GJ/day	January 1, 2013 – March 31, 2013	AECO fixed price swap	Cdn $3.105
Crude Oil	200 bbls/day	January 1, 2013 – December 31, 2013	WTI call option	Cdn $100.00
Crude Oil	500 bbls/day	July 1, 2012 – December 31, 2012	WTI fixed price swap	Cdn $96.70
Crude Oil	300 bbls/day	January 1, 2013 – June 30, 2013	WTI extendable swap (extendable for one year)	Cdn $96.70

These contracts as at September 30, 2012 had an unrealized gain of $94,123 and an unrealized loss of $458,948 that have been recorded on the balance sheet.

Royalty expenses for the third quarter of 2012 were $4.49/boe or $1,096,844, representing 10% of revenue, compared to a royalty expense for the second quarter of 2012 of $2.03/boe or $404,655, representing 5% of revenue. The increase in royalties as a percentage of revenue for the three months ended September 30, 2012 compared to the second quarter of 2012 was related to royalties for a full quarter of the Echoex properties which had an average royalty rate of 16% as a percentage of revenue, offset by a lower royalty rate for Tamarack's legacy properties.

Comparison to the third quarter of 2011 saw royalty expense of $4.12/boe or $417,793, representing 8% of revenue. The increase in royalties as a percentage of revenue in the third quarter of 2012, as compared to the third quarter of 2011 was related to the Echoex properties which had an average royalty rate of 16% as a percentage of revenue, offset by a lower royalty rate for Tamarack's legacy properties.

Royalty expenses for the first nine months of 2012 were $2.98/boe or $1,660,478, representing 7% of revenue, compared to a royalty expense for the first nine months of 2011 of $1.40/boe or $351,560, representing 3% of revenue. The increase in royalties as a percentage of revenue during the first nine months of 2012 as compared to the same period in 2011 was related to the Echoex properties which had an average royalty rate of 13% as a percentage of revenue, offset by a lower royalty rate for Tamarack's legacy properties and a net GCA royalty credit of $633,691 received in the first nine months of 2011.

Production Expenses

	Three months ended September 30,			Nine months ended September 30,		
	2012	2011	% change	**2012**	2011	% change
Gross costs	**$3,015,064**	$1,062,664	184	**$6,452,769**	$2,565,537	152
Total ($/boe)	**$12.33**	$10.49	18	**$11.59**	**$10.21**	14

Production expenses for the third quarter of 2012 were $12.33/boe compared to $11.76/boe incurred during the second quarter of 2012. On a dollar basis, overall costs increased in the third quarter of 2012 by 29% to $3,015,064 from the $2,345,691 incurred during the second quarter of 2012. The increase in per unit costs during the quarter was the result of the higher per unit cost ($14.00/boe during the quarter) properties acquired from Echoex being accounted for over a full quarter. The increase in total production costs resulted from a 21% increase in production and the higher per unit cost.

Production costs on a boe basis were $12.33/boe in the third quarter of 2012 as compared to $10.49/boe during the third quarter of 2011. Production expenses for the three months ended September 30, 2012 increased by 184% to $3,015,064 compared to $1,062,664 in the same period in 2011. The increase in total production costs resulted from a 141% increase in production and the increase in higher cost oil production weighting, along with the Echoex acquisition of higher per unit cost properties.

Production costs on a boe basis were $11.59/boe in the first nine months of 2012 as compared to $10.21/boe during the first nine months of 2011. Production expenses for the nine months ended September 30, 2012 increased by 152% to $6,452,769 compared to

$2,565,537 in the same period in 2011. The increase in total production costs resulted from a 121% increase in production and the increase in higher cost oil production weighting, along with the Echoex acquisition of higher per unit cost properties.

Operating Netback

	Three months ended September 30,			Nine months ended September 30,		
($/boe)	**2012**	2011	% change	**2012**	2011	% change
Average realized sales	**45.12**	51.54	(12)	**41.24**	43.68	(6)
Royalty expenses	**(4.49)**	(4.12)	9	**(2.98)**	(1.40)	113
Production expenses	**(12.33)**	(10.49)	18	**(11.59)**	(10.21)	14
Operating field netback	**28.30**	36.93	(23)	**26.67**	32.07	(17)
Realized commodity hedging gain (loss)	**1.92**	–	–	**(0.67)**	–	
Operating netback	**30.22**	36.93	(18)	**26.00**	32.07	(19)

The operating netback for the third quarter of 2012 increased by 28% to $30.22/boe compared to $23.69/boe during the second quarter of 2012. The increase was the result of the portion of overall higher netback production related to liquids increasing (49% vs. 42%), a realized hedging gain of $1.92/boe compared to a realized hedging loss of $1.90/boe during the second quarter of 2012, partially offset by higher royalty and production expenses on a per unit basis.

The operating netback for the third quarter of 2012 decreased by 18% to $30.22/boe compared to $36.93/boe during the third quarter of 2011. The decrease was the result of lower oil and natural gas liquids prices and lower natural gas prices, higher production expenses on a per unit basis, partially offset by a realized hedging gain.

The operating netback for the first nine months of 2012 decreased by 19% to $26.00/boe compared to $32.07/boe during the first nine months of 2011. The decrease was the result of lower oil and natural gas liquids prices and lower natural gas prices, higher royalty and production expenses on a per unit basis, a realized hedge loss, partially offset by the portion of overall higher netback production related to liquids increasing (43% vs. 29%).

General and Administrative Expenses

	Three months ended September 30,			Nine months ended September 30,		
	2012	2011	% change	**2012**	2011	% change
Gross costs	**$1,050,905**	$811,813	29	**$2,638,679**	$2,494,434	6
Capitalized costs and recoveries	**(306,444)**	(146,709)	109	**(529,359)**	(388,716)	36
General and administrative costs	**$744,461**	$665,104	12	**$2,109,320**	$2,105,718	0
Total ($/boe)	**$3.05**	$6.57	(54)	**$3.79**	$8.38	(55)

General and administrative expenses for third quarter of 2012 were $3.05/boe on costs of $744,461 compared to $3.61/boe on costs of $720,959 in the second quarter 2012. The decrease in cost per boe was the result of a 21% increase in production.

General and administrative expenses for the third quarter of 2011 were $6.57/boe on costs of $665,104. The decrease in the cost per boe in the third quarter of 2012 was the result of a 141% increase in production.

General and administrative expenses for the nine months ended September 30, 2012 were $3.79/boe on costs of $2,109,320 compared to $8.38/boe on costs of $2,105,718 during the first nine months of 2011. The decrease in the cost per boe for the nine months ended September 30, 2012 was the result of a 121% increase in production.

Stock-Based Compensation Expenses

Stock-based compensation expenses of $221,944 and $872,138 relating to the preferred shares and stock options for the three and nine months ended September 30, 2012 was lower compared to $325,263 and $1,421,126 for the same periods in 2011. The decrease is the result of stock-based compensation expense being calculated based on graded vesting periods that are front end loaded and as such expenses were higher in 2011 due to the timing of issuance of preferred shares and options in 2010.

The Company capitalized $122,977 and $411,338 of stock-based compensation expenses relating to exploration and development activities for the three and nine months ended September 30, 2012 compared to $106,948 and $440,511 for the same periods in 2011.

For the three and nine months ended September 30, 2012 the Company issued 1,190,416 new options at a weighted average exercise price of $1.97 per share.

The fair value of each stock option grant issued in 2011 and 2012 were estimated on the date of grant using the Black-Scholes option pricing model with the following assumptions: average expected volatility of 80 percent, weighted average risk-free interest rate of 1.8 %, zero dividend yield and expected life of five years. The average fair value of stock options granted during the three month period ended September 30, 2012 was $1.26 per option and the average fair value of stock options granted the year ended December 31, 2011 was $3.12 per option. The Company has not re-priced any stock options.

Interest

Interest expense, net of interest income, was $383,948 and $690,255 for the three and nine months ended September 30, 2012 compared to interest expense, net of interest income, of $17,332 and $4,705 for the same periods in 2011. The Company has drawn $37,966,373 on its revolving operating demand line at September 30, 2012, compared to being drawn $4,197,016 on its line at September 30, 2011. The increase in average amount drawn resulted in the increase in interest expense.

Depletion, Depreciation, Amortization and Accretion

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

	Three months ended September 30,			Nine months ended September 30,		
	2012	2011	% change	**2012**	2011	% change
Depletion and depreciation	**$4,746,524**	$1,659,841	186	**$10,020,381**	$3,503,182	186
Amortization of undeveloped leases	**1,165,738**	1,118,141	4	**3,534,182**	3,148,371	–
Accretion	**66,048**	10,060	557	**143,618**	28,847	398
Total	**$5,978,310**	$2,788,042	114	**$13,698,181**	$6,680,400	105
Depletion and depreciation ($/boe)	**$19.42**	$16.38	19	**$17.99**	$13.93	29
Amortization ($/boe)	**4.77**	11.04	(57)	**6.35**	12.52	–
Accretion ($/boe)	**0.27**	0.10	170	**0.26**	0.11	136
Total ($/boe)	**$24.46**	$27.52	(11)	**$24.60**	$26.56	(7)

Depletion, depreciation, amortization and accretion expense on a boe basis for the third quarter of 2012 was 2% higher at $24.46/boe as compared to $23.86/boe during the second quarter of 2012. The rate increase was primarily the result of an increase in the overall Company depletion and depreciation rate as the portion of overall production related to oil (49% to 42%) increases, partially offset by the straight line depreciation of undeveloped leases being relatively constant over quarters against a 21% increase in production. Depletion, depreciation, amortization and accretion expense for the third quarter of 2012 was $5,978,310 compared to $4,761,526 during the second quarter of 2012. The 26% increase in depletion depreciation, amortization and accretion expense was the result of the 21% increase in production.

Depletion, depreciation, amortization and accretion expense on a boe basis for the third quarter of 2012 was 11% lower at $24.46/boe as compared to $27.52/boe during the third quarter of 2011. The rate decrease was primarily the result of the straight line depreciation of undeveloped leases being relatively constant over quarters against a 141% increase in production. Depletion, depreciation, amortization and accretion expense for the third quarter of 2012 was $5,978,310 compared to $2,788,042 during the third quarter of 2011. The 114% increase in depletion, depreciation, amortization and accretion expense was the result of the 141% increase in production and the higher depletion, depreciation, amortization and accretion rate.

Depletion, depreciation, amortization and accretion expense on a boe basis for the nine months ended September 30, 2012 was 7% lower at $24.60/boe as compared to $26.56/boe during the same period in 2011. The rate decrease was primarily the result of the straight line depreciation of undeveloped leases being relatively constant over quarters against a 121% increase in production. Depletion, depreciation, amortization and accretion expense for the nine months ended September 30, 2012 was $13,698,181 compared to $6,680,400 during the same period in 2011. The 105% increase in depletion depreciation, amortization and accretion expense was the result of the 121% increase in production and the higher depletion, depreciation, amortization and accretion rate.

Income Taxes

The Company did not incur any cash tax expense in the three and nine months ended September 30, 2012, nor does it expect to pay any cash taxes in 2012 based on current commodity prices, forecast taxable income, existing tax pools and planned capital expenditures.

For the three and nine months ended September 30, 2012, a deferred income tax reduction of $896 and $136,138 were recognized as compared to deferred income tax expense of $66,063 and a reduction of $279,073 for the same periods in 2011.

Net Loss and Funds from Operations

The Company had a net loss of $554,006 ($0.02 per share basic and diluted) during the three months ended September 30, 2012 and a net loss of $1,684,302 ($0.07 per share basic and diluted) during the nine months ended September 30, 2012 compared to net loss of $137,246 ($0.01 per share basic diluted) and a net loss of $621,576 ($0.04 per share basic and diluted) for the same periods in 2011.

Funds from operations during the three and nine months ended September 30, 2012 were $6,150,404 ($0.21 per share basic and diluted) and $10,637,141 ($0.43 per share basic and diluted) compared to funds from operations of $3,042,122 ($0.20 per share basic and diluted) and $5,935,131 ($0.41 per share basic and diluted) for the same periods in 2011. The increase in funds from operations is the result of increased production from the Echoex acquisition and the successful 2012 drilling program combined with production shifting to a higher oil weighting.

Capital Expenditures (including exploration and evaluation expenditures)

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

	Three months ended September 30,			Nine months ended September 30,		
	2012	2011	% change	**2012**	2011	% change
Land	**$83,319**	$2,352,322	(96)	**$259,250**	$11,710,413	(98)
Geological & geophysical	**25,311**	19,143	32	**(32,746)**	101,852	(132)
Drilling and completion	**6,556,437**	5,845,840	12	**22,547,222**	18,773,652	20
Equipment and facilities	**1,319,660**	1,702,522	(22)	**2,340,706**	2,885,661	(19)
Capitalized G&A	**(52,900)**	31,610	(267)	**(100,032)**	90,590	(210)
Office equipment	**11,860**	3,659	224	**17,539**	9,249	90
Total capital expenditures	**$7,943,687**	$9,955,096	(20)	**$25,031,939**	$33,571,417	(25)
Proceeds from disposal of property, plant and equipment	**(750,000)**	–	–	**(1,175,000)**	(1,750,000)	(33)
Total net capital expenditures	**$7,193,687**	$9,955,096	(28)	**$23,856,939**	$31,821,417	(25)

During the third quarter of 2012, the Company drilled, completed and equipped two (1.0 net) Cardium oil wells at Lochend and two (1.1 net) Cardium oil wells at Garrington and drilled the first (0.9 net) of an eight (7.9 net) well Viking oil program (6.9 net) at Redwater and (1.0 net) Westlock. The Company also drilled three (2.8 net) heavy oil wells, one of which was completed and placed on production after the end of the third quarter, one is awaiting completion and another was dry and abandoned (cost of dry hole was $649,755). Tamarack also incurred costs associated with attaining surface locations and drilling licences associated with the remainder of its 2012 drilling program. The Company's undeveloped acreage was 130,804 acres at the end of the quarter. Tamarack's 2012 capital expenditure guidance of spending $30 – $35 million, disclosed on April 19, 2012, assumed the Company would spend $10.1 million in the third quarter of 2012 compared to the actual capital expenditures net of dispositions of $7.2 million. To date the Company has spent $23.9 million compared to capital expenditure guidance of $27.0 million. Tamarack expects to be at the high end of its capital expenditure guidance range for 2012.

During the third quarter of 2012 the Company also disposed of non-core, non-producing gas assets acquired in the Echoex acquisition for $750,000.

Liquidity and Capital Resources

Tamarack's working capital deficiency was $41,640,882 at September 30, 2012, which included debt of $24,608,588 acquired in the Echoex acquisition. Tamarack's working capital deficiency at September 30, 2011, was $5,622,925. Tamarack's net debt to annualized third quarter funds from operations at September 30, 2012 was 1.7 times.

At September 30, 2012 and November 13, 2012 there were 29,706,752 common shares, 1,688,082 preferred shares and 1,569,583 options outstanding. The preferred shares were unchanged from December 31, 2011 and the options outstanding at December 31, 2011 were 379,167. The Company had 24,508,769 weighted average basic common shares outstanding during the nine month period in 2012.

On August 15, 2012 the Company increased its operating demand line of credit to $50,000,000 and added a $15,000,000 non-revolving acquisition/development demand line. 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% 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 has been secured by a $155,000,000 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.

Pursuant to the terms of the credit facility, the Company has provided the covenant that at all times its working capital ratio shall be not less than 1 to 1. The working capital ratio is defined under the terms of the credit facilities as current assets, including the undrawn portion of the revolving credit facility, to current liabilities, excluding any current bank indebtedness.

Subsequent to September 30, 2012, the Company increased its operating demand line of credit to $57,500,000. The next scheduled review is February 1, 2013. As available lending limits of the facilities are based on the bank's interpretation of the Company's reserve and future commodity prices, there can be no assurances as to the amount of available facilities that will be determine at each scheduled review.

On April 17, 2012 the Company issued 5,500,000 common shares at a price of $3.00 per common share for gross proceeds of $16,500,000. The net proceeds from the Offering were initially used to pay down bank debt incurred as a result of funding the $10,000,000 cash component of the Echoex acquisition and to accelerate the Company's 2012 oil focused drilling program.

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. 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.

Contractual Obligations

In the normal course of business the Company has obligations which represent contracts and other commitments with an estimated payment of $82,520 for the remainder of 2012; and $175,017 for 2013. These obligations are related to office lease commitments.

On November 25, 2011, the Company issued 729,167 flow-through common shares related to Canadian exploration expenditures for gross proceeds of $3,500,000. Under the terms of the flow-through share agreement, the Company is required to renounce the $3,500,000 of qualifying oil and natural gas expenditures effective December 31, 2011. The Company has incurred $3,113,267 of qualifying expenditures, with the balance of $386,733 to be incurred on or prior to December 31, 2012.

Guidance

There were no changes made to the production and capital expenditure guidance announced on April 19, 2012.

For 2012, the Company has a $30-35 million capital expenditure budget approved by the Board of Directors. It is designed to focus on Cardium oil horizontal drilling in Lochend/Garrington, Viking oil horizontal drilling in Redwater and heavy oil drilling in Saskatchewan. It is expected that approximately 90% of the budgeted capital expenditures will be allocated to drilling, completions and facilities costs associated with adding production. The $30-35 million capital program will be funded by funds from operations, the equity raised in April 2012 and bank debt.

The 2012 budget and guidance is a best estimate on certain assumptions including operating costs and commodity prices and will be regularly monitored by management. The 2012 budget is based on the following commodity prices: Edmonton Par pricing of $75.00/bbl for the June to December, 2012 period and 2012 average AECO prices of $2.15/GJ. The priority is to proactively manage the capital program as it relates to operational success and fluctuating commodity prices with a goal to maintain financial flexibility and achieve the 2012 average production guidance of 2,000 to 2,200 boe/d. The Company's goal is to exit at a production rate of approximately 2,600 to 2,700 boe/d.

Future Accounting Policy Changes

As at January 1, 2015, the Company will be required to adopt IFRS 9, "Financial Instruments", which is the result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The adoption of this standard should not have a material impact on the Company's consolidated financial statements.

In May 2011, IFRS 10 "Consolidated Financial Statements" was issued which sets out the principles for the presentation and preparation of consolidated financial statements when an entity controls one or more other entities. IFRS 10 replaces SIC-12 "Consolidation-Special Purpose Entities" and parts of IAS 27 "Consolidated and Separate Financial Statement" and is effective for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

In May 2011, IFRS 11 "Joint Arrangements" was issued to address reporting inconsistencies. This standard requires a single method to account for interests in jointly controlled entities, focusing on the rights and obligations of a joint arrangement, rather than its legal form (as is currently the case). IFRS 11 supersedes IAS 31 "Interests in Joint Ventures" and SIC-13 "Jointly Controlled Entities-Non-Monetary Contributions by Venturers", and is effective for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

In May 2011, IFRS 12 "Disclosure of Interests in Other Entities" was issued. This comprehensive standard applies to entities that have an interest in a subsidiary, a joint arrangement, an associate or an unconsolidated structured entity. IFRS 12 is effective for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

In May 2011, IFRS 13 "Fair Value Measurements" was issued. This standard defines fair value, setting out a single IFRS framework for measuring fair value and required disclosures about fair value measurements. IFRS 13 is to be applied for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

Selected Quarterly Information

Three Months Ended	**Sep. 30, 2012**	Jun. 30, 2012	Mar. 31, 2012	Dec. 31, 2011	Sep. 30, 2011	Jun. 30, 2011	Mar. 31, 2011	Dec. 31, 2010
Sales Volumes								
Natural gas *(mcf/d)*	**8,074**	7,672	5,047	6,390	3,847	3,835	4,021	4,386
Oil and NGL's *(bbls/d)*	**1,311**	914	401	442	460	230	119	125
Average boe/d *(6:1)*	**2,657**	2,193	1,242	1,507	1,101	869	789	856
Product Prices								
Natural gas *($/mcf)*	2.34	1.94	2.22	3.39	3.83	4.07	3.88	3.79
Oil and NGL's *($/bbl)*	77.03	78.19	84.07	89.87	91.38	96.49	85.51	81.13
Oil equivalent *($/boe)*	45.12	39.38	36.14	40.72	51.56	43.46	32.67	31.28
(000s, except per share amounts)								
Financial Results								
Gross revenues	**11,028**	7,857	4,083	5,645	5,222	3,437	2,320	2,464
Funds from (used in) operations	**6,150**	2,809	1,678	2,912	3,042	2,242	651	955
Per share – basic	**0.21**	0.10	0.11	0.18	0.20	0.15	0.06	0.08
Per share – diluted	**0.21**	0.10	0.11	0.18	0.20	0.14	0.06	0.08
Net Income(loss)	**(554)**	565	(1,695)	(2,442)	(137)	235	(719)	(2,205)
Per share – basic	**(0.02)**	0.02	(0.10)	(0.15)	(0.01)	0.02	(0.06)	(0.19)
Per share – diluted	**(0.02)**	0.02	(0.10)	(0.15)	(0.01)	0.01	(0.06)	(0.19)
Additions to property and equipment, net of proceeds	**7,944**	10,418	6,670	8,824	9,955	12,032	11,584	7,710
Total assets	**147,879**	145,511	69,221	64,955	62,912	57,890	54,675	35,566
Working capital (deficiency)	**(41,641)**	(40,425)	(12,614)	(7,614)	(5,623)	1,303	10,441	(1,162)
Decommissioning obligations	**11,679**	11,383	1,882	1,873	1,251	1,208	1,156	1,111
Deferred income tax	**(9,997)**	(10,208)	(3,382)	(2,921)	(2,724)	(2,790)	(2,805)	(2,106)

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

- The volatility in commodity prices, particularly natural gas and the effect this has had on revenue and net income (loss).

- The volatility in forward price curves also affects the mark to market calculation which results in swings in earnings.

- Oil volumes grew in Q3 2012 due to successful drilling at Lochend, Garrington and Red Water, and full quarter production from the Echoex Ltd. acquisition. Oil and natural gas liquids weighting has increased from 15% of total production in early 2011 to 49% in Q3 2012.

- On April 17, 2012 the Company acquired Echoex Ltd. Since the closing, this acquisition added $3,222,812 to oil and natural gas revenue and contributed $458,071 to net income.

- The Company recorded $1,065,190 in transaction costs related to the Echoex acquisition in Q2 and Q3 2012.

- The Cardium Oil drilling program started in Q4 2010 has increased funds from operations and the Company's average production.

- The Company recorded impairment charges on its natural gas related CGU's due to falling gas prices in the amount of $2,032,000 in Q4 2010, $498,000 in Q1 2011 and $1,408,000 in Q4 2011.

- The Company experienced an 18% reduction in production between Q1 2012 and Q4 2011 due to a reduction of drilling activity in Q1 2012 compared to previous quarters and the decline of two (1.5 net wells) Buck Lake wells that came on-stream in Q4 2011. The Company also experienced a 35% decrease in the realized gas prices between Q1 2012 and Q4 2011.

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 outline 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 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 in 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 a number of business risks, both known and unknown, with respect to its oil and gas exploration, development and production activities that could cause actual results or events to differ materially from those forecast. Most of these risks (financial, operational or regulatory) are not within the Company's control. While the following sections discuss some of these risks they should not be construed as exhaustive.

Financial Risks

Financial risks include commodity pricing; exchange and interest rates; and volatile markets.

Commodity price fluctuations result from market forces completely out of the Company's control and can significantly affect the Company's financial results. In addition, fluctuations between the Canadian dollar and the US dollar can also have a significant impact. Expenses are all incurred in Canadian dollars while crude oil, and to some extent natural gas, prices are based on reference prices denominated in US dollars. As a result of both of these factors Tamarack may enter into derivative instruments to partially mitigate the effects of downward price volatility. To evaluate the need for hedging, Management, with direction from the Board of Directors, monitors future pricing trends together with the cash flow necessary to fulfill capital expenditure requirements. Tamarack will only enter into a hedge to reduce downside uncertainty of pricing, not as a speculative venture.

Operational Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of Tamarack depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, existing reserves and their subsequent production will decline over time as they are exploited. A future increase in Tamarack's reserves will depend not only on its ability to explore and develop any properties it may have; but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that further commercial quantities of oil and natural gas will be discovered or acquired by Tamarack.

Tamarack endeavors to mitigate these risks by, among other things, ensuring that its employees are highly qualified and motivated. Prior to initiating capital projects the Tamarack technical team completes an economic analysis, which attempts to reflect the risks involved in successfully completing the project. In an effort to mitigate the risk of not finding new reserves, or of finding reserves that are not economically viable, Tamarack utilizes various technical tools, such as 2D and 3D seismic data, rock sample analysis and the latest drilling and completing technology.

Insurance is in place to protect against major asset destruction or business interruption, including well blow-outs and pollution. In addition, Tamarack cultivates long-term relationships with its suppliers in an effort to ensure good service regardless of the current cycle of oil and gas activity.

Operational risk is mitigated by having Tamarack staff 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 and 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 we 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 production rates;
- Tamarack's primary focus areas for production growth;

- future tax liabilities;
- the interest rates under Tamarack's credit facilities;
- flow-through expenditure obligations;
- future capital expenditures and capital program funding;
- derivative contracts and Tamarack's commodity price and foreign exchange rate risk management activities; and
- the timing and impact of implementing new accounting policies.

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 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;
- the continued availability of capital and skilled personnel;
- the ability to obtain financing on acceptable terms;
- the impact of increasing competition;
- the ability of the Company to secure adequate product transportation;
- the ability to enter into future commodity derivative contracts on acceptable terms; and
- the continuation of the current tax and regulatory regime.

Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated or implied by such forward-looking statements due to a number of factors and risks. These include:

- the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production;
- delays or changes in plans with respect to exploration or development projects or capital expenditures;
- volatility in market prices for oil and natural gas;
- uncertainties associated with estimating oil and natural gas reserves;

- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- marketing and transportation;
- environmental risks;
- competition for, among other things, capital, acquisition of reserves, undeveloped lands and skilled personnel;
- the ability to access sufficient capital from internal and external sources; and
- changes in tax, royalty and environmental legislation.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. Additional information on these and other factors that could affect the business, operations or financial results of Tamarack are included in reports on file with applicable securities regulatory authorities, including but not limited to Tamarack's revised Annual Information Form for the year ended December 31, 2011, 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)

	September 30, 2012	December 31, 2011
Assets		
Current assets:		
Accounts receivable	$6,772,634	$2,363,091
Prepaid expenses and deposits	579,863	484,512
Fair value of financial instruments (note 3)	94,123	–
	7,446,620	2,847,603
Property, plant and equipment (note 5)	115,674,007	42,713,355
Exploration and evaluation assets (note 6)	14,855,734	16,473,198
Deferred tax asset	9,997,196	2,921,241
	$147,973,557	$64,955,397
Liabilities and Shareholders' Equity		
Current liabilities:		
Bank debt (note 10)	$37,966,373	$1,027,231
Accounts payable and accrued liabilities	11,027,006	9,434,535
Fair value of financial instruments (note 3)	458,948	364,887
	49,452,327	10,826,653
Decommissioning obligations (note 7)	11,679,282	1,873,296
Deferred flow-through share premium	67,678	303,199
Shareholders' equity:		
Share capital	110,897,929	75,675,082
Contributed surplus	7,672,684	6,389,208
Deficit	(31,796,343)	(30,112,041)
	86,774,270	51,952,249
Subsequent event (note 13)		
	$147,973,557	$64,955,397

See accompanying notes to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Interim Statements of Comprehensive Loss
For the three and nine months ended September 30, 2012 and 2011
(unaudited)

	Three Months ended September 30,		Nine Months ended September 30,	
	2012	2011	2012	2011
Revenue:				
Oil and natural gas	$11,028,380	$5,222,421	$22,968,291	$10,980,057
Royalties	(1,096,844)	(417,793)	(1,660,478)	(351,560)
Other income	6,015	–	19,897	–
Realized gain (loss) on financial instruments (note 3)	470,555	–	(373,035)	–
Unrealized gain (loss) on financial instruments (note 3)	(605,297)	–	2,393,364	–
	9,802,809	4,804,628	23,348,039	10,628,497
Expenses:				
Production	3,015,064	1,062,664	6,452,769	2,565,537
General and administration	744,461	665,104	2,109,320	2,105,718
Transaction costs (note 4)	114,229	–	1,065,190	–
Stock-based compensation	221,944	325,263	872,138	1,421,126
Finance	449,996	27,392	833,873	33,552
Depletion, depreciation and amortization	5,912,262	2,777,982	13,554,563	6,651,553
Gain on disposition of property, plant and equipment	(750,000)	–	(1,175,000)	(1,763,746)
Exploration impairment (note 6)	649,755	17,406	1,455,626	17,406
Impairment of property, plant and equipment	–	–	–	498,000
	10,357,711	4,875,811	25,168,479	11,529,146
Loss before taxes	(554,902)	(71,183)	(1,820,440)	(900,649)
Deferred income tax reduction (expense)	896	(66,063)	136,138	279,073
Comprehensive loss	$(554,006)	$(137,246)	$(1,684,302)	$(621,576)
Loss per share (note 9):				
Basic	$(0.02)	$(0.01)	$(0.07)	$(0.04)
Diluted	$(0.02)	$(0.01)	$(0.07)	$(0.04)

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, 2011	11,487,437	$49,942,178	$4,278,245	$(27,049,198)	$27,171,225
Issue of common shares	3,919,963	23,049,380	–	–	23,049,380
Issue of flow-through shares	862,500	4,100,000	–	–	4,100,000
Shares issued on acquisition	92,329	432,102	–	–	432,102
Share issue costs, net of tax of $466,870	–	(1,400,608)	–	–	(1,400,608)
Flow-through share premium	–	(684,500)	–	–	(684,500)
Stock-based compensation	–	–	2,347,493	–	2,347,493
Options exercised	33,801	236,530	(236,530)	–	–
Comprehensive loss	–	–	–	(3,062,843)	(3,062,843)
Balance at December 31, 2011	16,396,030	75,675,082	6,389,208	(30,112,041)	51,952,249
Issue of common shares	5,500,000	16,500,000	–	–	16,500,000
Shares issued on acquisition	7,810,722	19,683,016	–	–	19,683,016
Share issue costs, net of tax of $320,055	–	(960,169)	–	–	(960,169)
Stock-based compensation	–	–	1,283,476	–	1,283,476
Comprehensive loss	–	–	–	(1,684,302)	(1,684,302)
Balance at September 30, 2012	29,706,752	$110,897,929	$7,672,684	$(31,796,343)	$86,774,270

	Number of common shares	Share capital	Contributed surplus	Deficit	Total Shareholders equity
Balance at January 1, 2011	11,487,437	$49,942,178	$4,278,245	$(27,049,198)	$27,171,225
Issue of common shares	3,919,963	23,049,380	–	–	23,049,380
Shares issued on acquisition	92,329	432,102	–	–	432,102
Share issue costs, net of tax of $407,755	–	(1,193,719)	–	–	(1,193,719)
Stock-based compensation	–	–	1,861,637	–	1,861,637
Options exercised	33,801	236,530	(236,530)	–	–
Comprehensive loss	–	–	–	(621,576)	(621,576)
Balance at September 30, 2011	15,533,530	$72,466,471	$5,903,352	$(27,670,774)	$50,699,049

See accompanying note to the condensed consolidated interim financial statements.

TAMARACK VALLEY ENERGY LTD.

Condensed Consolidated Statements of Cash Flows
For the three and nine months ended September 30, 2012 and 2011
(unaudited)

	Three Months ended September 30,		Nine Months ended September 30,	
	2012	2011	2012	2011
Cash provided by (used in):				
Operating:				
Comprehensive loss	$(554,006)	$(137,246)	$(1,684,302)	$(621,576)
Items not involving cash:				
Depletion, depreciation and amortization	5,912,262	2,777,982	13,554,563	6,651,553
Impairment of property, plant and equipment	–	–	–	498,000
Stock-based compensation	221,944	325,263	872,138	1,421,126
Gain on disposition of property, plant and equipment	(750,000)	–	(1,175,000)	(1,763,746)
Accretion expense on decommissioning obligations	66,048	10,060	143,618	28,847
Unrealized gain(loss) on financial instruments	605,297	–	(2,393,364)	–
Exploration and evaluation impairment	649,755	–	1,455,626	–
Deferred income tax expense (reduction)	(896)	66,063	(136,138)	(279,073)
Funds from operations	6,150,404	3,042,122	10,637,141	5,935,131
Abandonment expenditures (note 7)	(9,037)	(10,783)	(81,554)	(22,095)
Changes in non-cash working capital (note 8)	267,355	1,968,622	(508,575)	107,300
Cash provided by operating activities	6,408,722	4,999,961	10,047,012	6,020,336
Financing:				
Change in bank debt	2,830,338	4,197,016	12,330,554	4,197,016
Proceeds from issuance of common shares	–	–	16,500,000	23,049,380
Share issue costs	76,823	(2,437)	(1,280,224)	(1,601,474)
	2,907,161	4,194,579	27,550,330	25,644,922
Investing:				
Property, plant and equipment additions	(6,390,811)	(787,099)	(21,160,669)	(1,421,405)
Exploration and evaluation additions	(1,552,876)	(9,167,997)	(3,871,270)	(32,150,012)
Corporate acquisition (Note 4)	–	–	(10,000,000)	–
Proceeds from disposal of property, plant and equipment	750,000	–	1,175,000	1,750,000
Changes in non-cash working capital (note 8)	(2,122,196)	(3,179,716)	(3,740,403)	(3,484,866)
	(9,315,883)	(13,134,812)	(37,597,342)	(35,306,283)
Change in cash and cash equivalents	–	(3,940,272)	–	(3,641,025)
Cash and cash equivalents, beginning of period	–	3,940,272	–	3,641,025
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 significant wholly owned subsidiaries, all of which are incorporated in Canada: Tamarack Acquisition Corp., Tamarack Valley Holdings Corp., Tamarack Valley Partnership and Echoex Ltd. The Company is engaged in the exploration for and 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.

On July 16, 2012 the Company consolidated its common shares on a 1 for 12 basis and all number of shares and per share amounts have been restated to reflect the consolidation.

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, 2011. 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, 2011.

The condensed consolidated interim financial statements were authorized for issue by the Board of Directors on November 13, 2012.

3. Derivatives:

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

3. Derivatives (continued):

The fair value of forward contracts and swaps is determined by discounting the difference between the contracted prices and published forward price curves as at the balance sheet date, using the remaining contracted oil and natural gas volumes and a risk-free interest rate (based on published government rates). The fair value of options and collars is based on option models that use level 2 inputs, being published information with respect to volatility, prices and interest rates. The derivatives are valued at future value to profit and loss and therefore carrying amount equals future value.

At September 30, 2012, the Company held derivative commodity contracts as follows:

Subject Contract	Notional Quantity	Term	Hedge Type	Strike Price
Natural Gas	800 GJ/day	August 1, 2012 – December 31, 2012	AECO fixed price swap	Cdn $2.45/GJ
Natural Gas	2,000 GJ/day	April 1, 2012 – December 31, 2012	AECO fixed price swap	Cdn $2.37/GJ
Natural Gas	1,500 GJ/day	January 1, 2013 – March 31, 2013	AECO fixed price swap	Cdn $3.105/GJ
Crude Oil	200 bbls/day	January 1, 2013 – December 31, 2013	WTI call option	Cdn $100.00
Crude Oil	500 bbls/day	July 1, 2012 – December 31, 2012	WTI fixed price swap	Cdn $96.70
Crude Oil	300 bbls/day	January 1, 2013 – June 30, 2013	WTI extendable swap (extendable for one year)	Cdn $96.70

These contracts as at September 30, 2012 had an unrealized gain of $94,123 and an unrealized loss of $458,948 that have been recorded on the balance sheet.

4. Acquisition – Echoex Ltd.:

Effective April 17, 2012, the Company acquired all of the issued and outstanding common shares of Echoex Ltd. ("Echoex"), a privately held junior oil and gas exploration company. As consideration the Company paid cash of $10,000,000 and issued 7,810,722 common shares with an assigned value of $19,683,016. The purpose of the acquisition was to expand the Company's exposure to the Redwater Viking oil trend. The common shares have been ascribed a fair value of $2.52 per common share issued, as determined based on the Company's closing share price at the date of closing, being April 17, 2012. In addition, the Company incurred transaction costs of $1,065,190, which were expensed through the statement of comprehensive loss. The operations of Echoex have been included in the results of the Company commencing April 17, 2012. The transaction was accounted for by the purchase method. The allocation of the purchase price, based on management's estimates of fair values, is as follows:

Total Consideration:		
Cash consideration paid	$	10,000,000
Share consideration (7,810,722 at $2.52 per share)		19,683,016
	$	**29,683,016**
Net Assets Acquired:		
Property, plant and equipment	$	60,415,482
Current assets		2,075,330
Current liabilities		(3,411,885)
Risk management contracts		(2,393,302)
Bank debt		(24,608,588)
Decommissioning obligations		(9,249,304)
Deferred tax asset		6,855,283
	$	**29,683,016**

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

4. Acquisition – Echoex Ltd. (continued):

Included in the statement of comprehensive loss are the following amounts for Echoex since the date of acquisition:

Oil and natural gas revenue	$	6,315,013
Comprehensive income		1,154,176

If Echoex had been acquired on January 1, 2012, the incremental oil and natural gas revenue and income recognized for the period ended September 30, 2012 and the pro forma results would have been as follows:

Period ended September 30, 2012	As stated	Echoex Ltd. Prior to acquisition	Pro Forma
Oil and natural gas revenue	$22,968,291	$4,711,089	$ 27,679,380
Comprehensive income (loss)	(1,684,302)	668,975	(1,015,327)

5. Property, plant and equipment:

	Oil and Natural gas Interests	Other Assets	Total
Cost:			
Balance at January 1, 2011	$30,636,503	$117,032	$30,753,535
Cash additions	2,867,311	14,541	2,881,852
Decommissioning costs	859,673	–	859,673
Stock-based compensation	589,717	–	589,717
Transfer from exploration and evaluation assets	25,716,782	–	25,716,782
Disposals	(2,993,881)	–	(2,993,881)
Balance at December 31, 2011	57,676,105	131,573	57,807,678
Cash additions	21,143,130	17,539	21,160,669
Stock-based compensation	411,338	–	411,338
Decommissioning costs	494,618		494,618
Corporate acquisition	60,415,482		60,415,482
Transfer from exploration and evaluation assets	731,101	–	731,101
Balance at September 30, 2012	$140,871,774	$149,112	$141,020,886
Depletion, depreciation and impairment losses:			
Balance at January 1, 2011	$10,174,216	$25,582	$10,199,798
Depletion and depreciation	5,739,713	27,565	5,767,278
Impairment loss	1,906,000	–	1,906,000
Disposals	(2,778,753)	–	(2,778,753)
Balance at December 31, 2011	15,041,176	53,147	15,094,323
Depletion and depreciation	10,002,670	17,711	10,020,381
Transfer from exploration and evaluation assets	232,175	–	232,175
Balance at September 30, 2012	$25,276,021	$70,858	$25,346,879

	Oil and Natural gas Interests	Other Assets	Total
Carrying amounts:			
At December 31, 2011	$42,634,929	$78,426	$42,713,355
At September 30, 2012	$115,595,753	$78,254	$115,674,007

5. Property, plant and equipment (continued):

The calculation of depletion at September 30, 2012 includes estimated future development costs of $78,300,000 (December 31, 2011 – $59,000,000) associated with the development of the Company's proved plus probable reserves and excludes salvage value of $6,000,000 (December 31, 2011 – $2,600,000).

6. Exploration and evaluation assets:

	Total
Cost:	
Balance at January 1, 2011	$7,215,465
Additions	39,513,938
Decommissioning costs	20,000
Acquisitions	432,102
Transfer to property, plant and equipment	(25,716,782)
Balance at December 31, 2011	21,464,723
Additions	3,871,270
Transfer to property, plant and equipment	(731,101)
Balance at September 30, 2012	$24,604,892
Amortization and impairment:	
Balance at January 1, 2011	$360,749
Amortization	4,244,120
Exploration and evaluation impairment	386,656
Balance at December 31, 2011	4,991,525
Amortization	3,534,182
Exploration and evaluation impairment	1,455,626
Transfer to property, plant and equipment	(232,175)
Balance at September 30, 2012	$ 9,749,158

	Total
Carrying amounts:	
At December 31, 2011	$16,473,198
At September 30, 2012	$14,855,734

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 nine months ended September 30, 2012 the Company determined that two heavy oil wells were not technically feasible and economically viable recognizing an impairment of $1,455,626 (September 30, 2011 – $17,406).

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 $12 million at September 30, 2012 (December 31, 2011 – $2 million), which is expected to be incurred between 2012 and 2038. A risk-free rate of 2.5% (December 31, 2011 - 2.5%) and an inflation rate of 2% (December 31, 2011 – 2%) were used to calculate the fair value of the decommissioning obligations at September 30, 2012. A reconciliation of the decommissioning obligations is provided below:

	September 30, 2012	December 31, 2011
Balance, beginning of the period	**$1,873,296**	$1,112,030
Liabilities incurred	**494,618**	879,673
Liabilities acquired	**9,249,304**	–
Expenditures	**(81,554)**	(34,366)
Liabilities disposed	**–**	(127,047)
Accretion	**143,618**	43,006
Balance, end of the period	**$11,679,282**	$1,873,296

8. Supplemental cash flow information:

Changes in non-cash working capital is comprised of:

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
Source/(use of cash):				
Accounts receivable	**$(998,371)**	$(1,573,017)	**$(4,409,543)**	$(2,866,562)
Prepaid expenses and deposits	**(77,137)**	(127,025)	**(95,351)**	(62,793)
Accounts payable and accrued liabilities	**(779,333)**	488,948	**1,592,471**	(448,211)
Working capital deficiency on acquisition	**–**	–	**(1,336,555)**	–
	$(1,854,841)	$(1,211,094)	**$(4,248,978)**	$(3,377,566)
Related to operating activities	**$267,355**	$1,968,622	**$(508,575)**	$107,300
Related to investing activities	**(2,122,196)**	(3,179,716)	**$(3,740,403)**	$(3,484,866)

9. Loss per share:

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

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	**2012**	2011
Net loss for the period	**$(554,006)**	$(137,246)	**$(1,684,302)**	$(621,576)
Weighted average shares - basic	**29,706,752**	15,533,530	**24,508,769**	14,485,121
Weighted average shares - diluted	**29,706,752**	15,533,530	**24,508,769**	14,485,121
Loss per share-basic	**$(0.02)**	$(0.01)	**$(0.07)**	$(0.04)
Loss per share-diluted	**$(0.02)**	$(0.01)	**$(0.07)**	$(0.04)

Per share amounts have been calculated using the weighted average number of shares outstanding. For the three and nine months ended September 30, 2012 and 2011, 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. Bank debt:

At September 30, 2012 the Company has a revolving operating demand line of $50,000,000 and a $15,000,000 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. 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.

Pursuant to the terms of the credit facility, the Company has provided the covenant that at all times its adjusted working capital ratio shall be not less than 1 to 1. The adjusted working capital ratio is defined under the terms of the credit facilities as current assets, including the undrawn portion of the revolving credit facility, to current liabilities, excluding any current bank indebtedness. At September 30, 2012, the Company had utilized the revolving operating demand line of credit in the amount of $37,966,373. The Company is in compliance with its covenant as at September 30, 2012.

11. Share capital:

At September 30, 2012 and December 31, 2011, the Company was authorized to issue an unlimited number of common shares and preferred shares without nominal or par value. On July 16, 2012 the common shares of the Company have been consolidated on a 12 to 1 basis. All shares, options and per share amounts have been restated to reflect the share consolidation.

12. Share-based payments:

(a) Preferred share plan:

Under the Company's preferred share plan, preferred shares are exchangeable into common shares upon payment of $3.12 per common share. Preferred shares are granted at the market price of the shares at the date of grant, have a five-year term and are exercisable at the exercise price and vest one-third on each of the first, second and third anniversaries from the date of grant.

As at September 30, 2012 there were 1,688,082 (December 31, 2011 – 1,688,082) preferred shares outstanding and 1,125,389 (December 31, 2011 – 562,694) preferred shares exercisable with an exercise price of $3.12 per common share. The remaining contractual life is 2.8 years.

(b) Stock option plan:

Under the Company's stock option plan it may grant up to 2,970,672 options to its employees, directors and consultants of which 1,569,583 options 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.

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

	Number of Options	Weighted-Average Exercise Price
Outstanding, January 1, 2011	70,833	$ 4.09
Granted	316,667	4.59
Expired	(8,333)	4.80
Outstanding, December 31, 2011	379,167	$ 4.49
Granted	1,190,416	1.97
Outstanding, September 30, 2012	1,569,583	$ 2.58

12. Share-based payments (continued):

(b) Stock option plan (continued):

The following table summarizes information about stock options outstanding and exercisable at September 30, 2012 (December 31, 2011 – 23,611 at $4.08):

	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)
$ 3.60 – 4.80	379,167	$ 4.49	3.7	136,112	$ 3.63
$ 1.86 – 1.98	1,190,416	$ 1.97	4.9	–	–

13. Subsequent event:

Subsequent to September 30, 2012, the Company increased its operating demand line of credit to $57,500,000 and continued to have available a $15,000,000 non-revolving acquisition/development demand line. The credit facility has been secured by a $155,000,000 debenture with a floating charge over all assets. The next schedule review is February 1, 2013. As available lending limits of the facilities are based on the bank's interpretation of the Company's reserve and future commodity prices, there can be no assurances as to the amount of available facilities that will be determine at each scheduled review.

Directors

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

Dean Setoguchi (1)

David Mackenzie (1)(2)(3)

Sheldon Steeves(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

Niels Gundesen
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 - TSXV

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