



MANAGEMENT DISCUSSION AND ANALYSIS

For the Six Months Ended June 30, 2012

Date of Report: August 9, 2012

The following is a discussion of the consolidated operating results and financial position of Dejour Energy Inc. (the “Company” or “Dejour”), including all its wholly-owned subsidiaries. It should be read in conjunction with the Company’s audited consolidated financial statements and notes thereto for the year ended December 31, 2011 and the condensed interim unaudited consolidated financial statements for the six months ended June 30, 2012. On March 9, 2011, the Company changed its name from Dejour Enterprises Ltd. to Dejour Energy Inc.

Effective January 1, 2011, the Company adopted International Financial Reporting Standards (“IFRS”) and the following disclosure, as well as its associated condensed interim consolidated financial statements, has been prepared in accordance with IFRS as issued by the International Accounting Standards Board.

All financial information in this MD&A is stated in Canadian dollars, the Company’s presentation currency, unless otherwise noted. Some numbers in this MD&A have been rounded to the nearest thousand for discussion purposes. Certain forward-looking statements are discussed in this MD&A with respect to the Company’s activities and future financial results. These are subject to risks and uncertainties that may cause projected results or events to differ materially from actual results or events. Readers should also read the Advisory section located at the end of this document, which provides information on Non-GAAP Measures, BOE Presentation and Forward-Looking Statements.



DEJOUR STRATEGY AND BUSINESS ENVIRONMENT

In 2012, deployment of capital is primarily driven by commodity prices, thus the Company's near term focus is on the liquids rich gas developments in the Kokopelli Field and at South Rangely in the Piceance Basin of the U.S. Rockies. These two developments provide the most effective way to generate positive returns while positioning the Company for a broad uplift in value assuming gas prices continue to recover from recent lows. Though it had been expected that the majority of the value of these two projects will come from the recovery of condensate and natural gas liquids ("NGL") produced in association with the natural gas, the recent uptick in the natural gas prices and decline in ethane prices has shifted the expected value of the future back towards natural gas without significantly effecting the expected return on the project.

Given recent softness in the prices of NGL, the Company's development program has been prudently adjusted and one well will be drilled in 2012 to meet the minimum investment required to preserve its lease position in the Kokopelli Field. Additional development drilling will be deferred until early 2013 and the size of the program will depend on the continued recovery of natural gas and NGL prices, which appear to have hit bottom in April and May of 2012 and rebounded to some extent from recent lows.

In addition to the focus on the initial development projects in the Piceance Basin, in 2012, the Company continues its work to optimize production and revenue from the Drake/Woodrush property in northeastern British Columbia. Through the first six months of 2011, essentially all of Dejour's capital investments were targeted to complete the development of the oil resources at Woodrush. During this time the Company successfully constructed new facilities and started up a waterflood of the Halfway "E" oil pool. Initial production response to the water injection was seen in June 2011 as the first of three producing wells in the field experienced an increase in oil production. In October 2011, the Company received approval of its application to the British Columbia Oil and Gas Commission to replace the current Daily Oil Allowable with a Voidage Replacement Scheme for the management of the waterflood. This approval allowed the Company to drill a third producer at the end of 2011 and to increase the water injection rate. As a result of this increased injection, an earlier production response is now expected in the two producing wells that have yet to respond to injection. The Company expects the full production response and peak production from Woodrush to occur in the second half of 2012.

BUSINESS OVERVIEW

The Company's common shares trade on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange AMEX ("NYSE-AMEX") under the symbol "DEJ". The Company ceased to trade on the TSX Venture Exchange ("TSX-V") and graduated to the TSX effective November 20, 2008.

The Company is in the business of acquiring, exploring and developing energy projects with a focus on oil and gas exploration in Canada and the United States. The Company holds approximately 112,000 net acres of oil and gas leases in the following regions:

- The Peace River Arch of northwestern British Columbia and northeastern Alberta, Canada.
- The Piceance, Paradox and Uinta Basins in the US Rocky Mountains.

On July 13, 2012, the Company announced that Mr. Robert Holmes, a director of the Company and a member of the Company's Audit Committee since 2008, has resigned from the Board of Directors.



Q2 2012 HIGHLIGHTS

In Q2 2012, the Company continued its focus on production optimization of the Drake/Woodrush property, while finalizing pre-drilling activities for the Kokopelli field development and drilling activities for the discovery well at South Rangely.

During the quarter, the Company achieved the following major objectives and also made significant progress on key strategic initiatives that resulted in:

1. In May 2012, the Company signed a commitment letter with an U.S. institutional lender (“Lender”), subject to certain closing conditions, for a US\$14 million debt financing that will be dedicated to fund the initial drilling program at Kokopelli Field in 2012. Subsequent to June 30, 2012, as a result of the slump in the prices of NGL, both the Company and the Lender have agreed to amend the initial line of credit to an amount not to exceed US\$7.5 million, subject to certain terms, conditions and requirements of the proposed loan, which are currently under discussion. Both the Company and the Lender remain in discussions with the intent of having a final loan agreement in place in the third quarter of 2012.
2. In June 2012, the Company successfully raised gross proceeds of US\$4.7 million in equity, allowing it to support exploration, development and acquisition of oil and gas properties and working capital purposes.

SELECTED CONSOLIDATED FINANCIAL RESULTS

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	\$	\$	\$	\$
Gross Revenues	1,771,000	1,816,000	3,699,000	3,400,000
Operating Cash Flow ⁽¹⁾	(496,000)	(260,000)	(964,000)	(753,000)
Operating Loss ⁽¹⁾	(1,261,000)	(797,000)	(2,716,000)	(1,994,000)
EBITDA ⁽¹⁾	324,000	591,000	786,000	(714,000)
Adjusted EBITDA ⁽¹⁾	(291,000)	6,000	(638,000)	(236,000)
Net Loss	(580,000)	(189,000)	(934,000)	(2,268,000)
Net loss per share	(0.004)	(0.002)	(0.007)	(0.019)

⁽¹⁾ A non-GAAP measure, which is defined under the Non-GAAP Measures section of the MD&A.



OIL AND GAS EXPLORATION AND PRODUCTION

During 2012, the Company further refined its focus toward the conversion of resources into reserves. As a result, the Company's asset characterization has moved toward more tangible low risk near term development projects, moderate risk appraisal opportunities and moderate to high risk exploration potential.

DEJOUR'S BUSINESS

Canadian Activities

The Company's wholly-owned subsidiary, Dejour Energy (Alberta) Ltd. ("DEAL"), currently has interests in oil and gas properties in the Peace River Arch located principally in northeastern British Columbia.

DEAL holds approximately 11,000 net acres concentrated in the Peace River Arch.

Production and Development Projects

Woodrush/Drake

In October 2011, Dejour received approval to operate the waterflood on a voidage replacement basis and in December drilled a third production well while increasing total injection from 1200 BWP/D to 2400 BWP/D. The start-up and subsequent enhancement of the waterflood marked the end of major capital investments in Woodrush. Dejour will concentrate on optimizing injection and production in the waterflood, controlling cost and increasing margins as the oil production is gradually ramped up to its maximum level in the second half of 2012. Woodrush oil production in the second quarter of 2012 was increased by about 6% over the first quarter of 2012.

Effective December 31, 2011, the Company's reserve evaluation valued the before tax discounted net present value 10% (NPV₁₀) of remaining proved reserves in the Woodrush oil pool at \$19 million, with proved and probable reserves valued at \$31 million net to Dejour's 75% working interest. The reserve estimation and economic evaluation dated December 31, 2011 was conducted by an independent firm, Deloitte & Touche LLP ("AJM Deloitte") of Calgary, Alberta.

US Activities

The Company's wholly-owned subsidiary, Dejour Energy (USA) Corp., currently holds approximately 101,000 net acres prospective for oil and gas exploitation in Colorado and Utah.

Kokopelli

The Company continued working with its partners to bring this project into production. Dejour has a 72% working interest in this 2,200 acre project which is ideally situated for exploitation of both the Williams Fork and Mancos shale bodies. The Williams Companies, Inc. and Bill Barrett Corporation are developing and producing on adjacent acreage to the east, west and north of the Company's acreage. Dejour USA has worked closely with important constituents including local citizenry and government, the Bureau of Land Management and the Colorado Division of Wildlife to develop a mutually acceptable development plan for this environmentally sensitive area. Construction of the first drilling pad commenced in the fourth quarter of 2011 with production expected to begin in the second half of 2012. According to National Instrument 51-101 standard in Canada, the reserves evaluation report for Dejour's leases at Kokopelli Field effective December 31, 2011, performed by Gustavson and Associates of Boulder, Colorado, showed the before tax discounted net present value 10% (NPV₁₀) of proved undeveloped reserves valued at \$94 million and proven plus probable undeveloped reserves valued at \$202 million.



South Rangely

In June 2011, the Company drilled and cased an evaluation well on this 5,500 gross acre (3,300 net acre) lease that is located just south of the Rangely field. The well was drilled and casing set on approximately 90 feet of gross Mancos "B" Sand and later successfully fractured and stimulated. The well flowed rich gas from the Mancos "B" Sand in commercial quantities. Analysis of the gas showed a higher NGL yield from the South Rangely discovery than that expected from our NGL development at the Kokopelli Field.

In March 2012, the formation of a federal exploration and production unit containing all of Dejour leasehold adjacent to the discovery well was approved by the Bureau of Land Management. The formation of this unit will allow the Company to continue to evaluate and develop its leases in South Rangely in a more efficient and environmentally sensitive manner than would have been possible if the development were pursued on individual leases.

West Grand Valley (Piceance Basin)

On the Company's West Grand Valley property, Dejour operates approximately 5,180 gross acres with a 72% working interest in an area of active drilling by EnCana Corporation, Laramie Energy II, LLC and Axia Energy, LLC. Success in developing the gas in the Lower Mancos (Niobrara) section has revitalized drilling interest in this area of the Piceance Basin. Included in the West Grand Valley property acreage is the 1400+ acre Roan Creek evaluation project. This project is located very close to and sandwiched between existing Williams Fork gas fields operated by Occidental and Chevron. While it is likely that the Williams Fork at Roan Creek will be somewhat thinner than is found to the east and west, Roan Creek has Mancos potential which can be tested via an exploratory tail to a Williams Fork Company appraisal well. During 2009, the various geologic and commercial studies conducted by the Company highlighted the potential at Roan Creek. As a result of those studies, the Company began to make plans for a single well drilling program. The permitting process is underway and drilling at Roan Creek will follow the first increment of drilling at Kokopelli.

Future Exploration and Evaluation

As a result of a reasonably comprehensive geologic and commercial study, Dejour has high graded two future development and appraisal projects including:

- Plateau (Piceance Basin) - This 3,014 acre (gross) project located south of Roan Creek has significant Williams Fork Company potential as evidenced by successful drilling by EnCana Corporation at acreage adjacent to the Company's holdings.
- North Rangely – This 19,280 acre (gross) project located north of the Rangely Field, is prospective for oil in the Lower Mancos (Niobrara), Dakota, Morrison and Phosphoria formations.

These potential developments will be deferred to at least 2013 as the current natural gas price has caused Dejour to delay the start of investments on its other leases in Colorado. Exploitation of these opportunities will in all likelihood proceed once developments at Kokopelli, South Rangely and Roan Creek have been advanced to the point that Company's cash flow and proved producing reserve base can support the additional development costs.



CAPITAL EXPENDITURES

Additions to property and equipment and exploration and evaluation assets:

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	\$	\$	\$	\$
Land acquisition and retention	126,334	83,457	148,779	120,282
Drilling and completion	608,263	834,065	1,082,546	2,217,733
Facility and pipelines	98,322	873,240	547,522	2,255,848
Capitalized general and administrative	187,770	214,291	406,687	314,109
Other assets	-	468	967	5,928
	1,020,689	2,005,521	2,186,501	4,913,900

DAILY PRODUCTION

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
By Product				
Oil and natural gas liquids (bbls/d)	215	185	210	161
Natural gas (mcf/d)	1,146	614	1,209	1,119
Total (boe/d)	406	287	411	347

The increase in oil production for both periods was the result of successful implementation of the waterflood in the Halfway "E" Pool on the Company's Woodrush property. The increase in natural gas production for both periods was primarily the result of the temporary curtailment of production due to maintenance related downtime at the regional gas processing plant in the 2nd quarter of 2011.

SHARE CAPITAL

The following is a summary of share transactions for the six months ended June 30, 2012 and the year ended December 31, 2011:

	Common Shares	
	# of Shares	\$ Value of shares
Balance at December 31, 2010	110,180,545	79,385,883
- Issue of shares on exercise of warrants and options	4,751,841	1,574,401
- Warrant liability reallocated on exercise of warrants	-	738,548
- Contributed surplus reallocated on exercise of options	-	167,070
- Shares issued via private placements, net of issuance costs	11,010,000	2,693,813
- Subscriptions receivable on exercise of options	950,000	516,246
Balance at December 31, 2011	126,892,386	85,075,961
- Issue of shares on exercise of warrants and options	3,893,683	1,465,812
- Warrant liability reallocated on exercise of warrants	-	285,689
- Contributed surplus reallocated on exercise of options	-	198,103
- Shares issued via private placements, net of issuance costs	18,130,305	3,248,011
Balance at June 30, 2012	148,916,374	90,273,576

As at August 9, 2012, the Company had 148,916,374 issued and outstanding common shares.



STOCK OPTIONS AND SHARE PURCHASE WARRANTS

The following table summarizes information about outstanding stock option transactions:

	Number of options	Weighted average exercise price
		\$
Balance at January 1, 2011	6,946,500	0.40
Options granted	3,212,500	0.35
Options exercised	(1,150,000)	0.35
Options cancelled (forfeited)	(200,000)	0.40
Options expired	(305,000)	0.45
Balance at December 31, 2011	8,504,000	0.39
Options granted	2,125,001	0.43
Options exercised	(925,000)	0.38
Options cancelled (forfeited)	(57,459)	0.41
Balance at June 30, 2012	9,646,542	0.40

Details of the outstanding and exercisable stock options as at June 30, 2012 are as follows:

	Outstanding			Exercisable		
	Number of options	Weighted average exercise price	contractual life (years)	Number of options	Weighted average exercise price	contractual life (years)
		\$			\$	
\$0.35	4,904,000	0.35	2.24	4,125,000	0.35	2.25
\$0.45	4,742,542	0.45	1.97	3,554,297	0.45	1.99
	9,646,542	0.40	2.11	7,679,297	0.40	2.13

As at June 30, 2012, none of the outstanding and exercisable stock options were “in the money” (the exercise price was less than the market trading price).

The following table summarizes information about outstanding warrant transactions:

	Number of Warrants	Weighted average Exercise price
		\$
Balance at January 1, 2011	21,010,455	0.44
Warrants granted	5,505,002	0.37
Warrants exercised	(4,551,841)	0.37
Warrants expired	(3,540,026)	0.48
Balance at December 31, 2011	18,423,590	0.43
Warrants granted	13,597,729	0.41
Warrants exercised	(2,968,683)	0.38
Balance at June 30, 2012	29,052,636	0.43



Details of the outstanding and exercisable warrants as at June 30, 2012 are as follows:

	Outstanding			Exercisable		
	Number of warrants	Weighted average exercise price	contractual life (years)	Number of warrants	Weighted average exercise price	contractual life (years)
		\$			\$	
\$0.40	3,642,856	0.40	3.38	3,642,856	0.40	3.38
\$0.55	4,015,151	0.55	1.98	4,015,151	0.55	1.98
\$0.40 US	7,700,000	0.41	2.48	7,700,000	0.41	2.48
\$0.40 US	13,597,729	0.41	4.93	-	-	-
\$0.46 US	96,900	0.47	2.34	96,900	0.47	2.34
	29,052,636	0.43	3.67	15,454,907	0.44	2.56

SELECTED FINANCIAL HIGHLIGHTS

(See “Non-GAAP Measures” section below for explanations)

Operating Cash Flow

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	\$	\$	\$	\$
Cash flows from (used in) operating activities - GAAP	(728,000)	(460,000)	(1,847,000)	(1,292,000)
Add: changes in non-cash operating working capital	232,000	200,000	883,000	539,000
Operating Cash Flow - Non-GAAP	(496,000)	(260,000)	(964,000)	(753,000)

Operating Netback

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	\$	\$	\$	\$
Gross Revenues	1,771,000	1,816,000	3,699,000	3,400,000
Less: Royalties	(291,000)	(348,000)	(621,000)	(585,000)
Less: Operating and transportation	(840,000)	(471,000)	(1,792,000)	(978,000)
Operating Netback	640,000	997,000	1,286,000	1,837,000

Operating Loss

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	\$	\$	\$	\$
Net loss	(580,000)	(189,000)	(934,000)	(2,268,000)
Add back (losses) and deduct gains:				
Impairment losses	-	187,000	9,000	195,000
Change in fair value of warrant liability	(681,000)	(795,000)	(1,791,000)	79,000
Operating Loss	(1,261,000)	(797,000)	(2,716,000)	(1,994,000)



EBITDA

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	\$	\$	\$	\$
Net loss	(580,000)	(189,000)	(934,000)	(2,268,000)
Deferred tax recovery	-	-	-	(187,000)
Finance costs	208,000	282,000	333,000	525,000
Amortization, depletion and impairment losses	696,000	498,000	1,387,000	1,216,000
EBITDA	324,000	591,000	786,000	(714,000)

Adjusted EBITDA

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
	\$	\$	\$	\$
EBITDA	324,000	591,000	786,000	(714,000)
Adjustments:				
Stock-based compensation	66,000	210,000	367,000	399,000
Change in fair value of warrant liability	(681,000)	(795,000)	(1,791,000)	79,000
Adjusted EBITDA	(291,000)	6,000	(638,000)	(236,000)

NON-GAAP MEASURES

Non-GAAP measures are commonly used in the oil and gas industry. Certain measures in this document do not have any standardized meaning as prescribed by IFRS and previous GAAP such as Operating Cash Flow, Operating Netback, Operating Loss, EBITDA and Adjusted EBITDA and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding our liquidity and our ability to generate funds to finance our operations.

Operating Cash Flow is a non-GAAP measure defined as cash flow from operating activities before changes in non-cash operating working capital items.

Operating Netback is a non-GAAP measure defined as gross revenues less royalties and operating and transportation expenses.

Operating Loss is a non-GAAP measure defined as net loss excluding non-cash items that management believes affects the comparability of operating results. These items may include, but are not limited to, unrealized financial instrument gain (loss), impairment losses and impairment reversals, gain (loss) on divestitures, and change in fair value of financial instruments.

EBITDA is a non-GAAP measure defined as net loss before income tax expense, finance costs, and amortization, depletion and impairment losses.

Adjusted EBITDA excludes certain items that management believes affects the comparability of operating results. Items excluded generally are non-cash items, one-time items or items whose timing or amount cannot be reasonably estimated.



RESULTS OF OPERATIONS – THREE MONTHS ENDED JUNE 30, 2012 AND 2011

Summary of Operational Highlights

Production and Netback Summary

	Three months ended June 30,	
	2012	2011
Production Volumes:		
Oil and natural gas liquids (bbls)	19,595	16,850
Gas (mcf)	104,321	55,851
Total (BOE)	36,982	26,158
Average Price Received:		
Oil and natural gas liquids (\$/bbls)	78.85	94.83
Gas (\$/mcf)	2.16	3.91
Total (\$/BOE)	47.88	69.44
Royalties (\$/BOE)	7.86	13.32
Operating and Transportation Expenses (\$/BOE)	22.72	18.01
Netbacks (\$/BOE)*	17.30	38.11

*See Non-GAAP Measures

Revenues

	Three months ended June 30,	
	2012	2011
	\$	\$
Gross Revenues	1,771,000	1,816,000
Royalties	(291,000)	(348,000)
Revenues, net of royalties	1,480,000	1,468,000
Financial instrument loss	-	(12,000)
Other income	8,000	8,000
Total revenue	1,488,000	1,464,000

For the three months ended June 30, 2012 (“Q2 2012”), the Company recorded \$1,771,000 in oil and natural gas sales as compared to \$1,816,000 in oil and natural gas sales for the three months ended June 30, 2011 (“Q2 2011”). The decrease in gross revenues was due to lower realized oil prices in the current quarter despite higher oil production. The increase in natural gas production for the current quarter was mainly the result of the temporary curtailment of production due to maintenance related downtime at the regional gas processing plant in the 2nd quarter of 2011.

Royalties for Q2 2012 decreased to \$291,000 from \$348,000 for Q2 2011, due to lower realized oil and gas prices despite higher production. Royalties are mainly driven by the varying production mix between oil and gas and market prices.



The following table summarizes the commodity prices realized by the Company and the crude oil and natural gas benchmark prices for the three months ended June 30, 2012 and 2011:

	Three months ended June 30,	
	2012	2011
	\$	\$
Dejour Realized Average Prices		
Oil and natural gas liquids (\$/bbl)	78.85	94.83
Natural gas (\$/mcf)	2.16	3.91
Total average price (\$/boe)	47.88	69.44
Average Benchmark Prices		
Edmonton Par (\$/bbl)	84.39	102.63
Natural gas - AECO-C Spot (\$ per mcf)	1.83	3.74

For the current quarter, Dejour's average realized natural gas prices reflected lower benchmark prices compared to Q2 2011. Oil prices received for Q2 2012 decreased to \$78.85 per barrel ("bbl"), compared to \$94.83 per bbl for Q2 2011. The decrease was due to the general downturn of the global economy, leading to lower commodity prices. In addition, the oil differential between West Texas Intermediate (WTI) oil to British Columbia light crude oil had increased due to pipeline constraints, resulting in lower realized prices for the Company's oil.

Operating and Transportation Expenses

Operating and transportation expenses include all costs associated with the production of oil and natural gas and the transportation of oil and natural gas to the processing plants. The major components of operating expenses include labour, equipment maintenance, workovers, fuel and power. Operating and transportation expenses for Q2 2012 increased to \$840,000 from \$471,000 for Q2 2011. The increase was due to the increase in production, increased repairs and maintenance of oil wells and higher waterflood activity.

Finance Costs and Change in Fair Value of Warrant Liability

Finance costs for the current quarter decreased to \$208,000 from \$282,000 for the same quarter in prior year. The decrease was primarily attributable to the line of credit facility obtained in September 2011 that bears a lower interest rate, compared to the bridge loan with a relatively higher interest rate. Included in the finance costs for the current quarter was \$129,000 of the expenses related to the US\$ denominated warrants issued as part of the US \$4.7 million equity offering closed in June 2012.

For both quarters, the non-cash change in fair value of warrant liability was a gain. The Company recorded a gain of \$681,000 for Q2 2012, compared to \$795,000 for Q2 2011. The warrant liability relates to the fair value of certain warrants that were issued in the previous equity financings. These warrants are denominated in US dollars, which is different than the functional currency of the Company. Under IFRS, they are classified as liabilities and any change in the fair value is recognized in the profit or loss. Changes in fair value result from volatility in the Company's share prices and fluctuations in the US/Canadian dollar exchange rates. Lower share prices of the Company in the current quarter resulted in a lower valuation for these warrants and a lower non-cash valuation gain for the current quarter.



Stock Based Compensation

For the current quarter, the Company recorded non-cash stock based compensation expenses of \$66,000, compared to \$210,000 for Q2 2011. The significant decrease in stock based compensation expense was due to the lower number of stock options vested in the current quarter.

Amortization, Depletion and Impairment Losses

For the current quarter, amortization, depletion and impairment losses were \$696,000, compared to \$498,000 for Q2 2011. Amortization and depletion of property and equipment for Q2 2012 was \$696,000, compared to \$312,000 for Q2 2011. The increase in amortization and depletion expenses for the current quarter was due to the increase in production. Impairment losses of \$186,000 for Q2 2011 were recognized upon the expiry of certain leases for exploration and evaluation assets.

Net Loss and Operating Loss

The Company's net loss for the current quarter was \$580,000 or \$0.004 per share, compared to a net loss of \$189,000 or \$0.002 per share for the same quarter in 2011. The increase in net loss was primarily due to the increase in operating and transportation expenses, and amortization and depletion and impairment losses. This was partly offset by the decrease in general and administrative expenses, finance costs, stock based compensation and fair value of warrant liability.

The Company's operating loss for the current quarter was \$1,261,000, compared to \$797,000 for Q2 2011. The increase was primarily due to the increase in operating and transportation expenses and amortization and depletion. This was partly offset by the decrease in general and administrative expenses, finance costs and stock based compensation.



RESULTS OF OPERATIONS – SIX MONTHS ENDED JUNE 30, 2012 AND 2011

Summary of Operational Highlights

Production and Netback Summary		
	Six months ended June 30,	
	2012	2011
Production Volumes:		
Oil and natural gas liquids (bbls)	38,166	29,126
Gas (mcf)	219,981	202,517
Total (BOE)	74,830	62,878
Average Price Received:		
Oil and natural gas liquids (\$/bbls)	83.53	89.64
Gas (\$/mcf)	2.32	3.90
Total (\$/BOE)	49.43	54.07
Royalties (\$/BOE)	8.30	9.30
Operating and Transportation Expenses (\$/BOE)	23.95	15.30
Netbacks (\$/BOE)*	17.18	29.47

*See Non-GAAP Measures

Revenues

	Six months ended June 30,	
	2012	2011
	\$	\$
Gross Revenues	3,699,000	3,400,000
Royalties	(621,000)	(585,000)
Revenues, net of royalties	3,078,000	2,815,000
Financial instrument loss	(55,000)	(59,000)
Other income	16,000	17,000
Total revenue	3,039,000	2,773,000

For the six months ended June 30, 2012, the Company recorded \$3,699,000 in oil and natural gas sales as compared to \$3,400,000 in oil and natural gas sales for the six months ended June 30, 2011. The increase in gross revenues was due to higher oil production. The increase in natural gas production for the six months ended June 30, 2012 was mainly the result of the temporary curtailment of production due to maintenance related downtime at the regional gas processing plant in the 2nd quarter of 2011.

Royalties for the six months ended June 30, 2012 increased to \$621,000 from \$585,000 for the same period in prior year, due to higher oil production. Royalties are mainly driven by the varying production mix between oil and gas. Production for the six months ended June 30, 2012 had the highest relative % of oil and oil production which is subject to higher royalty rate compared to the royalty rate for natural gas.



The following table summarizes the commodity prices realized by the Company and the crude oil and natural gas benchmark prices for the six months ended June 30, 2012 and 2011:

	Six months ended June 30,	
	2012	2011
	\$	\$
Dejour Realized Average Prices		
Oil and natural gas liquids (\$/bbl)	83.53	89.64
Natural gas (\$/mcf)	2.32	3.90
Total average price (\$/boe)	49.43	54.07
Average Benchmark Prices		
Edmonton Par (\$/bbl)	88.54	95.57
Natural gas - AECO-C Spot (\$ per mcf)	2.17	3.76

For the six months ended June 30, 2012, Dejour's average realized natural gas prices reflected lower benchmark prices compared to the same period of 2011. Oil prices received for the six months ended June 30, 2012 decreased to \$83.53 per barrel ("bbl"), compared to \$89.64 per bbl for the same period of 2011. The decrease was due to the general downturn of the global economy, leading to lower commodity prices.

Operating and Transportation Expenses

Operating and transportation expenses include all costs associated with the production of oil and natural gas and the transportation of oil and natural gas to the processing plants. The major components of operating expenses include labour, equipment maintenance, workovers, fuel and power. Operating and transportation expenses for the six months ended June 30, 2012 increased to \$1,792,000 from \$978,000 for the same period in prior year. The increase was due to the increase in production and higher expenses related to waterflood activity.

Finance Costs and Change in Fair Value of Warrant Liability

Finance costs for the six months ended June 30, 2012 decreased to \$333,000 from \$525,000 for the same period in prior year. The decrease was mainly attributable to the line of credit facility obtained in September 2011 that bears a lower interest rate, compared to the bridge loan with a relatively higher interest rate. Included in the finance costs for the six months ended June 30, 2012 was \$129,000 of the expenses related to the US\$ denominated warrants issued as part of the US \$4.7 million equity offering closed in June 2012.

The non-cash change in fair value of warrant liability for the six months ended June 30, 2012 was a gain of \$1,791,000, compared to a loss of \$79,000 for the same period in prior year, primarily due to the decrease of the Company's share prices. The warrant liability relates to the fair value of certain warrants that were issued in the previous equity financings. These warrants are denominated in US dollars, which is different than the functional currency of the Company. Under IFRS, they are classified as liabilities and any change in the fair value is recognized in the profit or loss. Changes in fair value result from volatility in the Company's share prices and fluctuations in the US/Canadian dollar exchange rates. Lower shares prices of the Company in the current quarter resulted in a lower valuation for these warrants and a non-cash valuation gain for the current period.

Stock Based Compensation

Non-cash stock based compensation expenses for the six months ended June 30, 2012 were comparable to the amount recorded for the same period in prior year.



Amortization, Depletion and Impairment Losses

For the six months ended June 30, 2012, amortization, depletion and impairment losses were \$1,387,000, compared to \$1,216,000 for the same period in prior year. Amortization and depletion of property and equipment for the six months ended June 30, 2012 was \$1,377,000, compared to \$1,021,000 for the same period in prior year. The increase in amortization and depletion expenses was due to the increase in production. Impairment losses for both periods were recognized upon the expiry of certain leases for exploration and evaluation assets.

Net Loss and Operating Loss

The Company's net loss for the six months ended June 30, 2012 was \$934,000 or \$0.007 per share, compared to a net loss of \$2,268,000 or \$0.019 per share for the same period of 2011. The decrease in net loss was primarily due to the non-cash valuation gain of \$1,791,000 from the decrease in fair value of warrant liability. This was partly offset by the increase in operating and transportation expenses.

The Company's operating loss for the six months ended June 30, 2012 was \$2,716,000, compared to \$1,994,000 for the same period of 2011. The increase was primarily due to the increase in operating and transportation expenses. This was partly offset by the decrease in general and administrative expenses and finance costs.

SUMMARY OF QUARTERLY RESULTS

The following summary for the eight most recently completed financial quarters ending June 30, 2012 details pertinent financial and corporate information, which is unaudited and prepared by management of the Company. For more detailed information, refer to related consolidated financial statements.

	2nd Quarter ended June 30, 2012 \$	1 st Quarter ended March 31, 2012 \$	4 th Quarter ended December 31, 2011 \$	3rd Quarter ended September 30, 2011 \$	2nd Quarter ended June 30, 2011 \$	1 st Quarter ended March 31, 2011 \$	4 th Quarter ended December 31, 2010 \$	3 rd Quarter ended September 30, 2010 \$
Gross Revenues	1,771,000	1,928,000	2,478,000	2,947,000	1,816,000	1,584,000	1,529,000	2,534,000
Net loss for the period	(580,000)	(354,000)	(8,430,000)	(346,000)	(189,000)	(2,079,000)	(1,857,000)	(631,000)
Basic and diluted net loss per common share	(0.004)	(0.003)	(0.069)	(0.003)	(0.002)	(0.018)	(0.018)	(0.006)

Variations in gross revenues and net loss for the periods above resulted primarily from the following factors:

1. The production level of oil and natural gas and realized oil and natural gas prices resulted in the variations in gross revenues. Increased revenues in the quarter ending September 30, 2011 reflected increased oil production due to the achievement of full allowable oil production level set by the OGC.
2. The production level of oil and natural gas resulted in the variations in operating and transportation expenses. Corporate development activities and strategic initiatives taken was the result of the fluctuations in general and administrative expenses. These two factors are the causes for the variations in net loss. In the quarter ending December 31, 2011, the increase in general and administrative expenses was associated with the year-end bonus accrual for fiscal 2011; this partly caused the increase in net loss for the quarter.

3. Other non-cash items, such as amortization, depletion and impairment losses and valuation gain (loss) for the warrants denominated in US dollars, also resulted in the variations in net loss. Increased net loss for the quarter ended December 31, 2011 was mainly due to the recognition of non-cash impairment losses of \$5.2 million and a non-cash valuation loss of \$2 million.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments consist of cash and cash equivalents, accounts receivable, bank line of credit, accounts payable, accrued liabilities and warrant liabilities. Management has determined that the fair value of these financial instruments approximates their carrying values due to their immediate or short-term maturity. Net smelter royalties and related rights to earn or relinquish interests in mineral properties constitute derivative instruments. No value or discounts have been assigned to such instruments as there is no reliable basis to determine fair value until properties are in development or production and reserves have been determined.

From time to time, the Company enters into derivative contracts such as forwards, futures and swaps in an effort to mitigate the effects of volatile commodity prices and protect cash flows to enable funding of its exploration and development programs. Commodity prices can fluctuate due to political events, meteorological conditions, disruptions in supply and changes in demand.

The primary risks and how the Company mitigates them are as follows:

(a) Credit Risk

Credit risk arises from credit exposure from joint venture partners and oil & gas marketers included in accounts receivable. The maximum exposure to credit risk is equal to the carrying value of the financial assets.

The Company is exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, and results of operations.

The objective of managing the third party credit risk is to minimize losses in financial assets. The Company assesses the credit quality of the partners, taking into account their financial position, past experience, and other factors. The Company mitigates the risk of collection by obtaining the partners' share of capital expenditures in advance of a project and by monitoring accounts receivable on a regular basis. As at June 30, 2012, no accounts receivable has been deemed uncollectible or written off during the period. The Company expects to collect the outstanding receivables in the normal course of operations.

(b) Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The nature of the oil and gas industry is capital intensive and the Company maintains and monitors a certain level of cash flow to finance operating and capital expenditures.

The Company's ongoing liquidity and cash flow are impacted by various events and conditions. These events and conditions include but are not limited to commodity price fluctuations, general credit and market condition, operation and regulatory factors, such as government permits, the availability of drilling and other equipment, lands and pipeline access, weather, and reservoir quality.



To mitigate the liquidity risk, the Company closely monitors its credit facility, production level and capital expenditures to ensure that it has adequate liquidity to satisfy its financial obligations.

(c) Market Risk

Market risk is the risk that changes in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Company's net earnings. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns. The Company utilizes financial derivatives to manage certain market risks. All such transactions are conducted in accordance with the risk management policy that has been approved by the Board of Directors.

(i) Foreign Currency Exchange Risk

Foreign currency exchange rate risk is the risk that the fair value of financial instruments or future cash flows will fluctuate as a result of changes in foreign exchange rates. Although substantially all of the Company's oil and natural gas sales are denominated in Canadian dollars, the underlying market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between the Canadian and United States dollars. Given that changes in exchange rate have an indirect influence, the impact of changing exchange rates cannot be accurately quantified. The Company had no forward exchange rate contracts in place as at or during the six months ended June 30, 2012.

(ii) Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. During the six months ended June 30, 2012, the Company was exposed to interest rate fluctuations on its credit facility which bore a floating rate of interest. The Company had no interest rate swaps or financial contracts in place at or during the six months ended June 30, 2012.

(iii) Commodity Price Risk

Revenues and consequently cash flows fluctuate with commodity prices and the US/Canadian dollar exchange rate. Commodity prices are determined on a global basis and circumstances that occur in various parts of the world are outside of the control of the Company. The Company protects itself from fluctuations in prices by using the financial derivative sales contracts. The Company entered into commodity price contracts to manage the risks associated with price volatility and thereby protect its cash flows used to fund its capital program. The Company had no commodity contracts in place at June 30, 2012.

FINANCIAL CONDITION, LIQUIDITY AND CAPITAL RESOURCES

Cash Balance and Cash Flow

The Company had cash and cash equivalents of \$3,678,000 as at June 30, 2012. In addition to the cash balance, the Company has an unused line of credit of \$1.5 million from a Canadian Bank.

Bank Line of Credit Financing

In September 2011, the Company obtained a \$7 million revolving operating demand loan ("line of credit"), including a letter of credit facility to a maximum of \$700,000 for a maximum one year term, from a Canadian Bank to refinance the bridge loan and to provide operating funds. The line of credit is at an interest rate of Prime + 1% (total 4% p.a. currently) and collateralized by a \$10,000,000 debenture over all assets of DEAL and a \$10,000,000



guarantee from Dejour Energy Inc. In May 2012, the Company renewed the line of credit with the Canadian Bank. The next review date is scheduled on or before September 30, 2012, but subject to change at the discretion of the bank. As at June 30, 2012, a total of \$5.5 million of this facility was utilized.

According to the terms of the facility, DEAL is required to maintain an adjusted working capital ratio of greater than 1:1 at all times. The adjusted working capital ratio is defined as the ratio of (i) current assets (including any undrawn and authorized availability under the facility) less unrealized hedging gains to (ii) current liabilities (excluding current portion of outstanding balances of the facility) less unrealized hedging losses. As at June 30, 2012, DEAL is in compliance with the working capital ratio requirement.

Working Capital Position

As at June 30, 2012	\$
Working capital deficit	(4,109,000)
Non-cash warrant liability	1,476,000
Net cash working capital deficit	(2,633,000)
Add: Bank line of credit	5,481,000
Net cash working capital (excluding bank line of credit)	2,848,000

As at June 30, 2012, the Company had a working capital deficit of \$4,109,000. Excluding the non-cash warrant liability of \$1,476,000 related to the fair value of US\$ denominated warrants issued in previous equity financings, the net working capital deficit was \$2.6 million. The majority of the working capital deficit relates to the \$5.5 million outstanding bank line of credit, with a \$1.5 million credit limit remaining.

The bank line of credit is classified as current liabilities because it is a demand loan, subject to periodic review by the lender. Nevertheless, the Company intends to use it as a long-term financing due to the low cost of capital (currently 4% p.a.).

The Company plans to remedy the working capital deficiency through the following:

- Oil production is expected to increase in late 2012, generating more cash flow for the Company.
- If necessary and at the right market conditions, the Company may fund its working capital through additional debt, equity or joint venture financing, or disposal of non-core assets.

Capital Resources

During the first half of 2012, the Company successfully completed and tied into production the 3rd oil well and continued to optimize the waterflood at its Woodrush property in Canada. Most of the waterflood capital expenditures had already been spent and the capital expenditures at Woodrush in the remainder of 2012 are approximately \$400,000 to \$750,000. In the U.S., the Company is required to drill at least one well by November 2012 to preserve its lease position in the Kokopelli Field. The minimum expenditure for drilling one well is approximately \$2.9 million (net 71.43%). The Company plans to fund the expenditures through existing cash resources, unused line of credit, future production revenues and additional financing if necessary, including debt, equity or joint venture financing, or disposal of non-core assets. Based on the availability of financing on favorable terms, the Company may adjust its future capital expenditure plans.

Contractual Obligations

As of June 30, 2012, and in the normal course of business we have obligations to make future payments, representing contracts and other commitments that are known and committed.

Contractual Obligations (in thousands of dollars)	2012	2013	2014	2015	2016	Thereafter	Total
	\$	\$	\$	\$	\$	\$	\$
Operating lease obligations	132	260	167	49	-	Nil	608
Bank line of credit	5,481	-	-	-	-	Nil	5,481
Total	5,613	260	167	49	-	Nil	6,089

OFF-BALANCE SHEET ARRANGEMENTS

The Company has no material undisclosed off-balance sheet arrangements that have or are reasonably likely to have, a current or future effect on our results of operations or financial condition at June 30, 2012.

RELATED PARTY TRANSACTIONS

Except as disclosed elsewhere, during the six months ended June 30, 2012 and 2011, the Company entered into the following transactions with related parties:

- a) Compensation awarded to key management included a total of salaries and consulting fees of \$602,880 (2011 - \$682,085) and non-cash stock-based compensation of \$95,286 (2011 - \$258,965). Key management includes the Company's officers and directors. The salaries and consulting fees are included in general and administrative expenses. Included in accounts payable and accrued liabilities at June 30, 2012 is \$Nil (December 31, 2011 - \$396,618) owing to the companies controlled by the officers of the Company.
- b) The Company incurred a total of \$Nil (2011 - \$2,301) in finance costs to a company controlled by an officer of the Company.
- c) Included in interest and other income is \$15,000 (2011 - \$15,000) received from the companies controlled by officers of the Company for rental income.
- d) In December 2009, a company controlled by the CEO of the Company ("HEC") became a 5% working interest partner in the Woodrush property. Included in accounts payable and accrued liabilities at June 30, 2012 is \$20,626 (December 31, 2011 - \$53,668) owing to HEC.
- e) With respect to the private placement of 11,010,000 units issued at US\$0.30 per unit completed in February 2011, directors and officers of the Company purchased 2,000,000 units of this offering (see Note 13 to the annual consolidated financial statements for details).
- f) In December 2011, HEC exercised 250,000 warrants with an exercise price of US\$0.35 each that were issued in February 2011.
- g) In January 2012, directors and officers of the Company exercised 750,000 warrants with an exercise price of US\$0.35 each that were issued in February 2011.



INTERNATIONAL FINANCIAL REPORTING STANDARDS

On January 1, 2011, the Company adopted IFRS for financial reporting purposes, with a transition date of January 1, 2010. The consolidated financial statements for the year ended December 31, 2011, including required comparative information, were prepared in accordance with IFRS as issued by the International Accounting Standards Board (“IASB”) and interpretations of the International Financial Reporting Interpretations Committee (“IFRIC”). Previously, the Company prepared its financial statements in accordance with Canadian GAAP.

The adoption of IFRS did not have a material impact on the Company’s operations, strategic decisions, cash flow and capital expenditures. The most significant changes to the Company’s accounting policies related to the accounting for its property, plant and equipment and accounting for derivative financial instruments. Other impacted areas include stock-based compensation, foreign currency translation and accounting for flow through shares.

Further information on the IFRS accounting policies, impacts and reconciliation between previous Canadian GAAP and IFRS are provided in the Company’s Annual Consolidated Financial Statements for the year ended December 31, 2011 and which was also discussed in the Company’s Annual MD&A for the year ended December 31, 2011, both which are filed on SEDAR at www.sedar.com.

CRITICAL ACCOUNTING ESTIMATES

The Company makes estimates and assumptions about the future that affect the reported amounts of assets and liabilities. Estimates and judgments are continually evaluated based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. In the future, actual experience may differ from these estimates and assumptions.

The effect of a change in an accounting estimate is recognized prospectively by including it in profit or loss in the period of the change, if the change affects that period only; or in the period of the change and future periods, if the change affects both.

Information about critical judgments in applying accounting policies that have the most significant risk of causing material adjustment to the carrying amounts of assets and liabilities recognized in the condensed interim consolidated financial statements within the next financial year are discussed below:

Reserves

The estimate of reserves is used in forecasting the recoverability and economic viability of the Company’s oil and gas properties, and in the depletion and impairment calculations. The process of estimating reserves is complex and requires significant interpretation and judgment. It is affected by economic conditions, production, operating and development activities, and is performed using available geological, geophysical, engineering, and economic data. Reserves are evaluated at least annually by the Company’s independent reserve evaluators and updates to those reserves, if any, are estimated internally. Future development costs are estimated using assumptions as to the number of wells required to produce the commercial reserves, the cost of such wells and associated production facilities and other capital costs.

Exploration and evaluation expenditures

The application of the Company’s accounting policy for exploration and evaluation expenditure requires judgment in determining whether it is likely that future economic benefits will flow to the Company, which is based on assumptions about future events or circumstances. Estimates and assumptions made may change if new information becomes available. If, after expenditure is capitalized, information becomes available suggesting that the recovery of the expenditure is unlikely, the amount capitalized is written off in profit or loss in the period the new information becomes available.

Impairment

A CGU is defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructures, and the way in which management monitors the operations. The recoverable amounts of CGUs and individual assets have been determined based on the higher of fair value less costs to sell or value-in-use calculations. The key assumptions the Company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes, future operating and development costs. Changes to these assumptions will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value.

Derivative Financial Instruments

When estimating the fair value of derivative financial instruments, the Company uses third-party models and valuation methodologies that utilize observable market data. In addition to market information, the Company incorporates transaction specific details that market participants would utilize in a fair value measurement, including the impact of non-performance risk. However, these fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

Decommissioning liability

Decommissioning provisions have been recognized based on the Company's internal estimates. Assumptions, based on the current economic environment, have been made which management believes are a reasonable basis upon which to estimate the future liability. These estimates take into account any material changes to the assumptions that occur when reviewed regularly by management. Estimates are reviewed at least annually and are based on current regulatory requirements. Significant changes in estimates of contamination, restoration standards and techniques will result in changes to provisions from period to period. Actual decommissioning costs will ultimately depend on future market prices for the decommissioning costs which will reflect the market conditions at the time the decommissioning costs are actually incurred. The final cost of the currently recognized decommissioning provisions may be higher or lower than currently provided for.

Income taxes

The Company recognizes the net future tax benefit related to deferred tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecast cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize the net deferred tax assets recorded at the reporting date could be impacted. Additionally, future changes in tax laws in the jurisdictions in which the Company operates could limit the ability of the Company to obtain tax deductions in future periods. All tax filings are subject to audit and potential reassessment. Accordingly, the actual income tax liability may differ significantly from the estimated and recorded amounts.

Share-based payment transactions

The Company measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date at which they are granted. Estimating fair value for share-based payment transactions requires determining the most appropriate valuation model, which is dependent on the terms and conditions of the

grant. This estimate also requires determining the most appropriate inputs to the valuation model including the expected life of the share option, volatility and dividend yield.

DISCLOSURE OF INTERNAL CONTROLS

The Chief Executive Officer and Chief Financial Officer evaluated the effectiveness of the Company's disclosure controls and procedures as at June 30, 2012. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of these disclosure controls and procedures were effective as at June 30, 2012 to provide reasonable assurance that material information relating to the Company, including its consolidated subsidiaries, would be made known to them.

INTERNAL CONTROL OVER FINANCIAL REPORTING

The Chief Executive Officer and Chief Financial Officer are responsible for establishing and maintaining internal control over financial reporting ("ICFR"), as such term is defined in NI 52-109, for the Company. They have, as at June 30, 2012, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Chief Executive Officer and Chief Financial Officer of the Company are able to certify the design of the Company's internal control over financial reporting with no significant weaknesses in design of these internal controls that require commenting on in the MD&A.

It should be noted that while the officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the disclosure controls and procedures or internal controls over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

During the three months ended June 30, 2012, the Company continued to improve the period end review process and staff training to mitigate the weaknesses in ICFR previously identified.

Previously, period end review of the interim financial statements by management did not identify the error in the statement of cash flows for the three months ended June 30, 2011. Accordingly, cash flows from (used in) operating activities for the three months ended June 30, 2011 have been increased by \$1,652,825 and cash flows from (used in) investing activities have been decreased by \$1,652,825. The error has already been corrected in the interim financial statements for the six months ended June 30, 2012. This error had no impact on reported assets (including total cash and cash equivalents), liabilities, shareholders' equity, revenues, expenses, net and comprehensive loss for the period or net loss per common share basic and diluted.

With the improvement in operation of these controls, the Company believes it has mitigated the control weaknesses identified.

Except for the above, there were no changes in the Company's internal control over financial reporting that occurred during the three months ended June 30, 2012 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

The Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. As described on page 2 of this report, the Company experienced a change in its Audit Committee. It is not expected that this change will impact the effectiveness of internal control over financial reporting and disclosure. After the change, the Audit Committee is currently



composed of two independent directors who review accounting, auditing, internal controls and financial reporting matters.

WHISTLEBLOWER POLICY

Effective December 28, 2007, the Company's Audit Committee adopted resolutions that authorized the establishment of procedures for complaints received regarding accounting, internal controls or auditing matters, and for a confidential, anonymous submission procedure for employees and consultants who have concerns regarding questionable accounting or auditing matters. The implementation of the whistleblower policy is in accordance with the new requirements pursuant to Multilateral Instrument 52-110 Audit Committees, national Policy 58-201 Corporate Governance Guidelines and National Instrument 58-101 Disclosure of Corporate Governance Practices.

NON-GAAP MEASURES

Non-GAAP measures are commonly used in the oil and gas industry. Certain measures in this document do not have any standardized meaning as prescribed by IFRS and previous GAAP such as Operating Cash Flow, Operating Netback, Operating Loss, EBITDA and Adjusted EBITDA and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in this document in order to provide shareholders and potential investors with additional information regarding our liquidity and our ability to generate funds to finance our operations.

Operating Cash Flow is a non-GAAP measure defined as cash flow from operating activities before changes in non-cash operating working capital items.

Operating Netback is a non-GAAP measure defined as gross revenues less royalties and operating and transportation expenses.

Operating Loss is a non-GAAP measure defined as net loss excluding non-cash items that management believes affects the comparability of operating results. These items may include, but are not limited to, unrealized financial instrument gain (loss), impairment losses and impairment reversals, gain (loss) on divestitures, and change in fair value of financial instruments.

EBITDA is a non-GAAP measure defined as net loss before income tax expense, finance costs, and amortization, depletion and impairment losses.

Adjusted EBITDA excludes certain items that management believes affect the comparability of operating results. Items excluded generally are non-cash items, one-time items or items whose timing or amount cannot be reasonably estimated.

BOE PRESENTATION

Barrel of oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of gas to one barrel of oil. The term "BOE" may be misleading if used in isolation. A BOE conversion ratio of one barrel of oil to six mcf of gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head.

Total BOEs are calculated by multiplying the daily production by the number of days in the period.

FORWARD LOOKING STATEMENTS

Statements contained in this document about oil and gas production and operating activities that may constitute "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation as they involve the implied assessment that the resources described can be profitably produced in the future, based on certain estimates and assumptions. Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks, uncertainties and other factors that could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements. These risks, uncertainties and other factors include, but are not limited to, adverse general economic conditions, operating hazards, drilling risks, inherent uncertainties in interpreting engineering and geologic data, competition, reduced availability of drilling and other well services, fluctuations in oil and gas prices and prices for drilling and other well services, government regulation and foreign political risks, fluctuations in the exchange rate between Canadian and US dollars and other currencies, as well as other risks commonly associated with the exploration and development of oil and gas properties. Additional information on these and other factors, which could affect the Company's operations or financial results, are included in the Company's reports on file with Canadian and United States securities regulatory authorities. We assume no obligation to update forward-looking statements should circumstances or management's estimates or opinions change unless otherwise required under securities law.

ABBREVIATIONS

In this MD&A, the following abbreviations commonly used in the oil & gas industry have the meanings indicated:

Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
BOP/D	barrels per day
Mbbls	thousand barrels
Mmbtu	million British thermal units

Natural Gas

Mcf	thousand cubic feet
MCFD	thousand cubic feet per day
MMcf	million cubic feet
MMcf/D	million cubic feet per day
Mcfе	Thousand cubic feet of gas equivalent

Other

AECO	Intra-Alberta Nova Inventory Transfer Price (NIT net price of natural gas).
BOE	Barrels of oil equivalent. A barrel of oil equivalent is determined by converting a volume of natural gas to barrels using the ratio of 6 Mcf to one barrel.
BOE/D	Barrels of oil equivalent per day.
BCF	Billion cubic feet
BCFE	Billion cubic feet equivalent
MBOE	Thousand barrels of oil equivalent.
NYMEX	New York Mercantile Exchange.
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing Oklahoma for crude oil of standard grade.