DEJOUR ENERGY INC.
RESOURCEFUL. ENTERPRISING.

(formerly operating as Dejour Enterprises Ltd.)

MANAGEMENT DISCUSSION AND ANALYSIS

For the Six Months Ended June 30, 2011

Date of Report: August 9, 2011

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, 2010 and the condensed interim unaudited consolidated financial statements for the six months ended June 30, 2011 ("interim Consolidated Financial Statements"). 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"), which are also generally accepted accounting principles ("GAAP") for publicly accountable enterprises in Canada. In accordance with the standard related to the first time adoption of IFRS, the Company's transition date to IFRS was January 1, 2010 and therefore the comparative information for 2010 has been prepared in accordance with IFRS accounting policies.

This Management's Discussion and Analysis ("MD&A") and the interim Consolidated Financial Statements and comparative information have been prepared in accordance with IFRS. For all periods up to and including the year ended December 31, 2010, the Company prepared the Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("Pre-changeover Canadian GAAP" or "Previous GAAP"). The term "previous GAAP" refers to Canadian GAAP before the adoption of IFRS. Within this MD&A, the financial information prior to January 1, 2010 has been prepared following Canadian GAAP and, as allowed under IFRS 1, has not been re-presented. Further information regarding IFRS accounting policies can be found in the Changes in the Accounting Policies section, below, of this MD&A and the Notes to the interim Consolidated Financial Statements for the six months ended June 30, 2011.

All financial information in this MD&A is stated in Canadian dollars, the Company's reporting 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

As we exit the second quarter of 2011, the Company's business objective remains the economic development of key projects and growth opportunities, with the intention of enhancing shareholder value.

Year to date, oil has traded in a relatively narrow range of US$90 to US$100 per barrel. At the same time, natural gas prices continue to reflect concern that the market will remain over supplied well into next year by predominantly trading in a range of US$4.20 to US$4.50 per million btu on NYMEX.

Dejour remains focused on a development plan designed to allow the Company to continue its growth despite the lag in the recovery of the natural gas prices. Through the first six months of 2011, essentially all of Dejour's capital investments were targeted to developing our oil resources. As a result, we successfully completed the development and waterflood implementation of the Halfway oil pool located in our Woodrush property. At the same time, significant progress was made in the permitting and planning stages of our Piceance properties and in particular our project at Gibson Gulch where initial capital commitments are projected for the third and fourth quarter of 2011.

Dejour has received a mid-year updated reserve evaluation report on its Woodrush oil pool valuing the PV-10 proved reserves at $25 million, with proved and probable reserves valued at $42 million net to Dejour's 75% W.I. The reserve evaluation bears an effective date of June 30, 2011 and was conducted by an independent firm, AJM Petroleum Consultants ("AJM") of Calgary, Alberta, a qualified reserve evaluator. Production capacity from the field remains at approximately gross 1,260 BOE/D, (net 75% - 945 BOE/D), consisting of 800 BOP/D and 2.8 MMcf/D (net 75% - 600 BOP/D and 2.1 MMcf/D). However, current production is restricted by the British Columbia Oil and Gas Conservation Commission until the response from the water injection, commenced in March 2011, is seen at the producing wells. With the completion of the waterflood implementation in the first quarter of 2011, all major capital investments in the field have been made and we anticipate production and revenue will now gradually increase until the field reaches its anticipated peak production capacity of gross 1,260 BOE/D (net 945 BOE/D) in twelve to fifteen months. In 2011 Q2, the Halfway Pool began to show good response to the initial water injection as the producing gas oil ratio (GOR) dropped from 2,700 ft^3 per bbl to 250 ft^3 per bbl and the oil production rate began to increase. On July 31, 2011, the field production, still under gas oil ratio (GOR) restriction, was gross 1,114 BOE/D (net 834 BOE/D), consisting of 644 BOP/D and 2.8 MMcf/D (net 483 BOP/D and 2.1 MMcf/D).

In Colorado, Dejour commenced drilling an oil well at South Rangely in the 2nd quarter of 2011 targeting the oil potential in the Lower Mancos. The well will be fracture stimulated and tested in the third quarter of 2011. In the fourth quarter of 2011, a multi-well drilling program is projected to commence on Dejour's Gibson Gulch acreage where major Piceance operators Williams E&P and Bill Barrett Corp. have announced plans to increase drilling in 2011 on the properties surrounding Dejour's leasehold.

COMPANY 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 120,000 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.

Q2 2011 HIGHLIGHTS

In Q2 2011, the Company's focus was on increasing production, reserves, and operational efficiency at the Drake/Woodrush properties, while maintaining all prospective acreage holdings and positioning for renewed drilling activities in the United States as both the business environment and commodity prices improved.

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

1. With the water injection commenced at Woodrush Halfway oil pool in Northern Eastern British Columbia, Canada in March 2011, the Halfway Pool began to show good response to the initial water injection as the producing GOR dropped from 2,700 ft^3 per bbl to 250 ft^3 per bbl and the oil production rate began to increase. On July 31, 2011, the field production, still under GOR restriction, was gross 1,114 BOE/D (net 834 BOE/D), consisting of 644 BOP/D and 2.8 MMcf/D (net 483 BOP/D and 2.1 MMcf/D).

2. Subsequent to June 30, 2011, the Company signed a Commitment Letter with a Canadian bank for a $7 million revolving operating demand loan to refinance the bridge loan (due October 31, 2011) and to provide funds for general corporate purposes. The operating loan is at an interest rate of Prime + 1% (total 4% p.a. currently).

OIL AND GAS EXPLORATION AND PRODUCTION

During 2010 the Company further refined its focus toward on the conversion of resources into reserves. This process involved several distinct steps on the same continuum including:

- Classification and prioritization of acreage based on economic promise, technical robustness, infrastructural and logistic advantage and commercial maturity;
- Evaluation and development planning for top tier acreage positions;
- Developing partnerships within financial and industry circles to speed the exploitation process; and
- Aggressively bringing production on line where feasible.

As a result of these moves, the Company's asset characterization has moved toward more tangible low risk near term development projects, moderate risk appraisal opportunities and modest risk exploration potential with a benign lease expiration profile.

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.

As at June 30, 2011, DEAL's holdings approximately 13,000 net acres concentrated in the Peace River Arch.

Production and Development Projects

Woodrush/Drake

With the success of the drilling program in 2010, field production reached a record level in May 2010, averaging gross 970 BOED (728 BOED net). In December 2010, a waterflood project application was expedited and approval was received. The project was implemented in early 2011 with water injection commencing in March 2011. In the first quarter of 2011, gross production from the field was reduced to approximately 544 BOED (408 BOED net) in response to increasing gas production resulting from the decreasing pressure in the Halfway oil sand. Beginning in 2011 Q2, water injection was gradually increased to a level of 1,500 BWPD. In May 2011, the Halfway Pool began to show good response to the initial water injection as the producing gas oil ratio (GOR) dropped from 2,700 ft^3 per bbl to 250 ft^3 per bbl and the oil production rate began to increase. On July 31, 2011, the field production, still under GOR restriction, was gross 1,114 BOE/D (net 836 BOE/D), consisting of 644 BOP/D and 2.8 MMcf/D (net 483 BOP/D and 2.1 MMcf/D).

While some additional development drilling is likely to occur, the start-up of the waterflood marks the end of major capital investments in Woodrush. In 2011, Dejour will concentrate on optimizing injection and production in the waterflood, controlling cost and increasing margins on oil production as the oil production is gradually ramped up to its maximum level in the second half of 2012.

US Activities

Gibson Gulch

The Company is working with its partners to bring this low risk development project into production. Dejour's 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 is working 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. After all permits are received, current plans call for drilling to commence in the fourth quarter of 2011 with production expected to begin later in that year or early 2012. In 2010, the Company was granted approval to develop a 660 acre portion of the Gibson Gulch leases with 10-acre spacing. Approval of this spacing on the remainder of the lease acreage would enable Dejour and its partner to drill up to 220 wells (158 wells net to Dejour) from a few multi-well drilling pads to optimally exploit the gas reserves in the subsurface.

South Rangely

Evaluation and subsequent exploitation of an oil prospect at South Rangely, was deferred from the fourth quarter of 2010 to the second quarter of 2011, as a result of minor delays in the permitting process that prevented drilling from occurring before the winter drilling prohibitions designed to protect big game habitat. Despite a minor delay, the Company has commenced drilling an evaluation well on the 7,000 acre lease located just south of Rangely field. Recent advances in horizontal drilling and fracture stimulation technology have moved this previously marginal development into strong and healthy economic status. Successful drilling and production by an operator on offsetting acreage makes this project relatively low risk with the degree of economic success to be a function of the quality of the completion design. Success at South Rangely may allow the Company to revisit plans to evaluate and potentially exploit a 22,000 acre tract at the Company's North Rangely. This acreage had previously been subject to farm-out with Laramie Energy II LLC. Due to market conditions, Laramie declined to follow through with the farm-out terms and the acreage has reverted to Dejour control. In the 2nd quarter of 2011, a well was drilled and casing set on approximately 90 feet of gross Mancos C sand at South Rangely. The well will be fracture stimulated and tested in the third quarter of 2011.

West Grand Valley

In West Grand Valley, Dejour operates approximately 5100 gross acres with a 72% working interest in an area of active drilling by EnCana, Laramie Partners II and Axia. Here, success in developing the gas in the Lower Mancos (Niobrara) section has revitalized drilling interest in this area of the Piceance Basin. Included in this acreage is the 1400+ acre Roan Creek evaluation project. This opportunity 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 appraisal well. During 2009, the various geologic and commercial studies conducted by the Company highlighted the potential at Roan Creek which provided the driving force for a single well drilling program. Permits have been applied for and drilling at Roan Creek will follow the first increment of drilling at Gibson Gulch.

Future Exploration and Evaluation

Dejour retains a substantial amount of acreage prospective for oil and gas exploitation in other sections of the Piceance and Uinta basins. Dejour has approximately 109,000 net acre position that was sculpted over the 2006-2008 period.

As a result of a reasonably comprehensive geologic and commercial study in 2009, Dejour has high graded three future development and appraisal projects including:

- Plateau - This 4,500 acre (gross) project located south of Roan Creek in the Piceance Basin has significant Williams Fork potential as evidenced by successful drilling by EnCana Corporation at acreage adjacent to the Company's holdings.
- North Rangely – This 22,000 acre (gross) project located north of the Rangely Field, is prospective for oil in the Lower Mancos (Niobrara) and Dakota formations.

These potential developments will be deferred to at least 2013 as the slow recovery of natural gas prices has caused Dejour to delay the start of investments in Colorado. Exploitation of these opportunities will in all likelihood proceed only after developments at Gibson Gulch, South Rangely and Roan Creek reach equilibrium stage.

Capital Expenditures

Additions to property, plant and equipment and exploration and evaluation assets:

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
	$	$	$	$
Land acquisition and retention	83,457	103,677	120,282	168,954
Drilling and completion	834,065	7,582	2,217,733	1,115,691
Facility and pipelines	873,240	587,370	2,255,848	949,475
Capitalized general and administrative	214,291	184,086	314,109	904,290
Other assets	468	1,729	5,928	1,969
	2,005,521	884,444	4,913,900	3,140,379

Daily Production

	Three months ended June 30,		Six months ended June 30,	
	2011	2010	2011	2010
By Product				
Natural gas (mcf/d)	614	1,500	1,119	1,288
Oil and natural gas liquids (bbls/d)	185	349	161	244
Total (boe/d)	287	599	347	459

The decrease 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. This regional gas processing plant is operated by a third party and is not under the Company's control. Gas production resumed during the third week of July 2011.

The decrease in oil production for both periods was mainly attributed to the restricted production imposed by the Oil and Gas Conservation Commission of British Columbia from January to May 2011. In June 2011, oil production increased to an average gross 430 BOP/D (net 322 BOP/D).

SHARE CAPITAL

The following is a summary of share transactions for the six months ended June 30, 2011 and the year ended December 31, 2010:

	Common Shares	$
Balance at January 1, 2010	95,791,038	**75,722,520**
- General share issuance costs	-	(130,593)
- Shares issued via private placements, net of issuance costs	14,389,507	4,114,101
- Flow through share liability	-	(407,975)
Balance at December 31, 2010	110,180,545	**79,298,053**
- Issue of shares on exercise of warrants	200,000	77,712
- Warrant liability reallocated on exercise of warrants	-	34,851
- Shares issued via private placements, net of issuance costs	11,010,000	2,682,983
Balance at June 30, 2011	121,390,545	**82,093,599**

As at August 9, 2011, the Company had 121,390,545 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, 2010	4,416,682	0.45
Options granted	3,573,000	0.35
Options cancelled (forfeited)	(400,000)	0.39
Options expired	(643,182)	0.46
Balance at December 31, 2010	6,946,500	0.40
Options granted	3,212,500	0.35
Options cancelled (forfeited)	(120,000)	0.40
Options expired	(180,000)	0.45
Balance at June 30, 2011	9,859,000	0.39

Details of the outstanding and exercisable stock options as at June 30, 2011 are as follows:

	Outstanding			Exercisable		
	Number of options	Weighted average exercise price	Weighted average contractual life (years)	Number of options	Weighted average exercise price	Weighted average contractual life (years)
		$			$	
$0.35	6,373,000	0.35	3.04	3,436,625	0.35	3.12
$0.45	3,486,000	0.45	2.55	1,857,925	0.45	2.44
	9,859,000	0.39	2.87	5,294,550	0.39	2.88

STOCK OPTIONS AND SHARE PURCHASE WARRANTS (continued)

As at June 30, 2011, 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, 2010	14,736,150	0.47
Warrants granted	6,274,305	0.41
Balance at December 31, 2010	21,010,455	0.44
Warrants granted	5,505,002	0.34
Warrants exercised	(200,000)	0.39
Warrants expired	(3,491,090)	0.48
Balance at June 30, 2011	22,824,367	0.41

Details of the outstanding and exercisable warrants as at June 30, 2011 are as follows:

	Outstanding			Exercisable		
	Number of warrants	Weighted average exercise price	Weighted average contractual life (years)	Number of warrants	Weighted average exercise price	Weighted average contractual life (years)
		$			$	
$0.38	140,359	0.38	0.48	140,359	0.38	0.48
$0.40	4,642,856	0.40	4.38	4,642,856	0.40	4.38
$0.55	4,015,151	0.55	2.98	4,015,151	0.55	2.98
$0.35 US	5,505,002	0.34	0.60	5,505,002	0.34	0.60
$0.40 US	7,875,000	0.39	3.48	7,875,000	0.39	3.48
$0.46 US	645,999	0.44	3.35	645,999	0.44	3.35
	22,824,367	0.41	2.86	22,824,367	0.41	2.86

SELECTED FINANCIAL HIGHLIGHTS

Operating Cash Flow

	Three months ended June 30, 2011	2010	Six months ended June 30, 2011	2010
	$	$	$	$
Cash from (used) in operating activities - GAAP	(2,113,000)	609,000	(1,292,000)	(118,000)
Less: changes in non-cash working capital	(1,853,000)	49,000	(539,000)	304,000
Operating Cash Flow – Non-GAAP	(260,000)	560,000	(753,000)	(422,000)

Operating Cash Flow is a non-GAAP measure defined as net cash provided by operating activities before changes in assets and liabilities.

Operating Netback

	Three months ended June 30, 2011	2010	Six months ended June 30, 2011	2010
	$	$	$	$
Revenues	1,816,000	2,676,000	3,400,000	4,023,000
Less: Royalties	(348,000)	(551,000)	(585,000)	(772,000)
Less: Operating and transportation expenses	(471,000)	(660,000)	(978,000)	(1,505,000)
Operating Netback	997,000	1,465,000	1,837,000	1,746,000

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

EBITDA

	Three months ended June 30, 2011	2010	Six months ended June 30, 2011	2010
	$	$	$	$
Net loss	(189,000)	(52,000)	(2,268,000)	(2,636,000)
Deferred income tax recovery	-	-	(187,000)	(271,000)
Finance costs	282,000	280,000	525,000	536,000
Amortization, depletion and impairment losses	498,000	981,000	1,216,000	2,090,000
EBITDA	591,000	1,209,000	(714,000)	(281,000)

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

Adjusted EBITDA

	Three months ended June 30, 2011	2010	Six months ended June 30, 2011	2010
	$	$	$	$
EBITDA	591,000	1,209,000	(714,000)	(281,000)
Adjustments:				
Non-cash stock-based compensation	210,000	225,000	399,000	462,000
Change in fair value of warrant liability	(795,000)	(626,000)	79,000	(127,000)
Adjusted EBITDA	6,000	808,000	(236,000)	54,000

Adjusted EBITDA is a non-GAAP measure and 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.

NON-GAAP MEASURES

Within the MD&A references are made to terms commonly used in the oil and gas industry.

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

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

EBITDA is a non-GAAP measure defined as net income (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.

Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Operating Cash Flow, Operating Netback, 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.

SELECTED CONSOLIDATED FINANCIAL RESULTS

	Three months ended June 30, 2011	2010	Six months ended June 30, 2011	2010
	$	$	$	$
Gross revenues	1,816,000	2,676,000	3,400,000	4,023,000
Net loss	189,000	52,000	2,268,000	2,636,000

RESULTS OF OPERATIONS – THREE MONTHS ENDED JUNE 30, 2011 AND 2010

Summary of Operational Highlights

DEAL Production and Netback Summary

	Three Months Ended June 30, 2011	2010
Production Volumes:		
Oil and natural gas liquids (bbls)	16,850	31,753
Gas (mcf)	55,851	136,538
Total (BOE)	26,158	54,509
Average Price Received:		
Oil and natural gas liquids ($/bbls)	94.83	65.79
Gas ($/mcf)	3.91	4.29
Total ($/BOE)	69.44	49.08
Royalties ($/BOE)	13.32	10.11
Operating and Transportation Expenses ($/BOE)	18.01	12.11
Netbacks ($/BOE)*	38.11	26.87

*See Non-GAAP Measures

Revenues

	Three months ended June 30, 2011	2010
Revenue		
Gross revenues	$ **1,816,000**	$ 2,676,000
Royalties	**(348,000)**	(551,000)
Revenues, net of royalties	**1,468,000**	2,125,000
Financial instrument gain (loss)	**(12,000)**	92,000
Other income	**9,000**	8,000
Total revenue	**$ 1,465,000**	$ 2,225,000

For the three months ended June 30, 2011 ("Q2 2011"), the Company recorded $1,816,000 in oil and natural gas sales as compared to $2,676,000 in oil and natural gas sales for the three months ended June 30, 2010 ("Q2 2010"). The decrease in gross revenues was due to lower oil and gas production for the current quarter. The decrease in natural gas production was primarily the result of the temporary shut-in of gas production due to maintenance related downtime at the regional gas processing plant that is operated by a third party and is not under the Company's control. Gas production resumed during the third week of July 2011.

The decrease in oil production was mainly attributed to the restricted production imposed by the Oil and Gas Conservation Commission of British Columbia from January to May 2011. In June 2011, oil production increased to an average gross 430 BOP/D (net 322 BOP/D).

Despite lower gas production during Q2 2011, gross revenues increased by approximately 15% from Q1 2011 due to higher oil production in the month of June 2011.

Royalties for Q2 2011 decreased to $348,000 from $551,000 for Q2 2010, primarily due to lower oil and gas production. On a per BOE basis, royalties for Q2 2011 increased compared to the same quarter in 2010. This was the result of the Company's production mix more heavily weighted towards oil and oil production 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 three months ended June 30, 2011 and 2010:

	Three months ended June 30, 2011	2010
Dejour Realized Average Prices		
Natural gas ($/mcf)	$ 3.91	$ 4.29
Oil and natural gas liquids ($/bbl)	94.83	65.79
Total average price ($/boe)	$ 69.44	$ 49.08
Average Benchmark Prices		
Edmonton Par ($/bbl)	$ 102.63	$ 75.46
Natural gas - AECO-C Spot ($ per mcf)	$ 3.74	$ 3.86

Both the average natural gas sales prices and AECO-C daily spot prices for Q2 2011 were comparable to the prices received for Q2 2010. Oil prices received for Q2 2011 increased to $94.83 per barrel ("bbl"), compared to $65.79 per bbl for Q2 2010. The increase was due to the gradual recovery of the global economy, leading to higher 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 Q2 2011 decreased to $471,000 from $660,000 for Q2 2010.

On a per BOE basis, operating and transportation costs for Q2 2011 increased compared to Q2 2010. Operating and transportation costs per barrel have increased as fixed costs are spread over the lower production volumes during the current quarter compared to the same quarter in 2010.

General and Administrative Expenses

General and administrative expenses for Q2 2011 increased to $990,000 from $769,000 for Q2 2010. The increase was mainly due to non-recurring professional fees associated with the required conversion to the International Financial Reporting Standards (IFRS).

Finance Costs and Change in Fair Value of Warrant Liability

Finance costs for the current quarter were comparable to the same quarter in prior year.

The non-cash change in fair value of warrant liability for Q2 2011 increased to ($795,000) from ($626,000) for Q2 2010. 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. Due to lower US/Canadian dollar exchange rate at the end of June 30, 2011, this resulted in lower valuation for these warrants. However, this was offset by the increase of the Company's share prices in the current quarter.

Amortization, Depletion and Impairment Losses

For the current quarter, amortization, depletion and impairment losses were $498,000, compared to $981,000 for the same quarter in 2010. Amortization and depletion of property, plant and equipment for Q2 2011 was $312,000, compared to $961,000 for Q2 2010. The decrease in amortization and depletion expenses was mainly due to the increased reserves in the Drake/Woodrush area at the end of June 30, 2011 and the decrease in production. Impairment losses of $186,000 for Q2 2011, compared to $20,000 for Q2 2010, were recognized upon the expiry of the leases for exploration and evaluation assets.

Net Loss

The Company's net loss for the current quarter was $189,000 or $0.002 per share, compared to a net loss of $52,000 or $0.001 per share for the same quarter in 2010. The increase in net loss was primarily due to the decrease in revenues. This was partly offset by the decrease in operating and transportation, amortization, depletion and impairment losses and the decrease in fair value of warrant liability.

Operating Netbacks (See Non-GAAP Measures)

Operating netbacks for Q2 2011 decreased to $997,000 from $1,465,000 for Q2 2010. The decrease was due to lower revenues. This was partly offset by lower royalties and operating and transportation expenses. On a per BOE basis, operating netbacks for Q2 2011 increased compared to Q2 2010. This was the result of higher oil prices.

RESULTS OF OPERATIONS – SIX MONTHS ENDED JUNE 30, 2011 AND 2010

Summary of Operational Highlights

DEAL Production and Netback Summary

	Six Months Ended June 30, 2011	2010
Production Volumes:		
Oil and natural gas liquids (bbls)	29,126	44,188
Gas (mcf)	202,517	233,146
Total (BOE)	62,878	83,045
Average Price Received:		
Oil and natural gas liquids ($/bbls)	89.64	66.75
Gas ($/mcf)	3.90	4.60
Total ($/BOE)	54.07	48.44
Royalties ($/BOE)	9.30	9.30
Operating and Transportation Expenses ($/BOE)	15.30	18.09
Netbacks ($/BOE)*	29.47	21.06

*See Non-GAAP Measures

Revenues

	Six months ended June 30, 2011	2010
Revenue		
Gross revenues	**$ 3,400,000**	$ 4,023,000
Royalties	**(585,000)**	(772,000)
Revenues, net of royalties	**2,815,000**	3,251,000
Financial instrument gain (loss)	**(59,000)**	50,000
Other income	**17,000**	17,000
Total revenue	**$ 2,773,000**	$ 3,318,000

For the six months ended June 30, 2011, the Company recorded $3,400,000 in oil and natural gas sales as compared to $4,023,000 in oil and natural gas sales for the six months ended June 30, 2010. This 15% decrease in gross revenues was due to lower oil and gas production for the first six months of 2011 compared to the same period in 2010.

Royalties for the six months ended June 30, 2011 decreased to $585,000 from $772,000 for the same period in 2010, primarily due to lower oil and gas production.

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, 2011 and 2010:

	Six months ended June 30, 2011	Six months ended June 30, 2010
Dejour Realized Average Prices		
Natural gas ($/mcf)	$ 3.90	$ 4.60
Oil and natural gas liquids ($/bbl)	89.64	66.75
Total average price ($/boe)	$ 54.07	$ 48.44
Average Benchmark Prices		
Edmonton Par ($/bbl)	$ 95.57	$ 77.88
Natural gas - AECO-C Spot ($ per mcf)	$ 3.76	$ 4.61

Both the average natural gas sales prices and AECO-C daily spot prices for the six months ended June 30, 2011 were comparable to the prices received for the same period in 2010. Oil prices received for the six months ended June 30, 2011 increased to $89.64 per barrel ("bbl"), compared to $66.75 per bbl for the same period in 2010. The increase was due to the gradual recovery of the global economy, leading to higher 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, 2011 decreased to $978,000 or $15.30 per BOE from $1,505,000 or $18.09 per BOE for the same period in 2010.

On a per BOE basis, operating costs for the six months ended June 30, 2011 decreased compared to the same period in 2010. This was due to lower production and the addition of more readily available and less costly gas compression. During the first six months of 2010, while the installation of a new gas compressor lowered ongoing compression and operating costs, the Company first faced a few months of higher repair and maintenance costs, more compressor downtime and incurred approximately $220,000 for the installation of the new rental compressor, thus resulting in a higher operating cost per BOE for the period.

General and Administrative Expenses

General and administrative expenses for the six months ended June 30, 2011 increased to $1,950,000 from $1,756,000 for the same period in 2010. The increase was due to non-recurring professional fees associated with the required conversion to the International Financial Reporting Standards (IFRS).

Finance Costs and Change in Fair Value of Warrant Liability

Finance costs for the six months ended June 30, 2011 were decreased by about 2% to $525,000 from $536,000 in the same period in 2010.

The non-cash change in fair value of warrant liability for the six months ended June 30, 2011 increased to $79,000 from ($127,000) for the same period in 2010. 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. Due to the increase of the Company's share prices during the first six months of 2011, this resulted in higher valuation for these warrants.

Stock Based Compensation

For the six months ended June 30, 2011, the Company recorded non-cash stock based compensation expenses of $399,000, compared to $462,000 for the same period in 2010. Under IFRS, the Company is required to recognize the expenses using the graded accelerated method. This resulted in the recognition of higher expenses in the vesting periods immediately following the new grants and it contributed to the decrease in the stock-based compensation expenses for the first six months of 2011 compared to the same period in 2010. However, the decrease was partly offset by the new stock options granted in the first six months of 2011.

Amortization, Depletion and Impairment Losses

For the six months ended June 30, 2011, amortization, depletion and impairment losses were $1,216,000, compared to $2,090,000 for the same period in 2010. Amortization and depletion of property, plant and equipment for the first six months of 2011 was $1,021,000, compared to $1,710,000 for the same period of 2010. The decrease in amortization and depletion expenses was mainly due to the increased reserves in the Drake/Woodrush area at the end of June 30, 2011 and the decrease in production. Impairment losses of $195,000 for the first six months of 2011 were recognized upon the expiry of the leases for exploration and evaluation assets, while the impairment losses of $20,000 and $360,000 for the same period of 2010 were recognized upon the expiry of the leases for exploration and evaluation assets and property, plant and equipment, respectively.

Deferred Income Taxes

Deferred income tax recovery for the six months ended June 30, 2011 was $187,000, compared to $271,000 for the same period of 2010. Deferred income tax recovery for both periods was the result of the Company's renunciation of Canadian Exploration Expenditures ("CEE") to investors. Under IFRS, the renunciation of CEEs results in de-recognition of the flow-through share liability and recognition of deferred income tax recoveries. The Company's previously unrecognized deferred income tax assets relating to loss carry forwards were offset against deferred income tax liabilities from the renunciation of CEEs.

Net Loss

The Company's net loss for the six months ended June 30, 2011 was $2,268,000 or $0.019 per share, compared to a net loss of $2,636,000 or $0.027 per share for the same period of 2010. The decrease in net loss was primarily due to the decrease in operating and transportation expenses and amortization, depletion and impairment losses. This was partly offset by the decrease in revenues and the increase in fair value of warrant liability.

Operating Netbacks (See Non-GAAP Measures)

Operating netbacks for the six months ended June 30, 2011 increased to $1,837,000 or $29.47 per BOE from $1,746,000 or $21.06 per BOE for the same period of 2010. The increase in total operating netback was due to higher oil prices, lower royalties and operating and transportation expenses.

SUMMARY OF QUARTERLY RESULTS

The following summary for the eight most recently completed financial quarters ending June 30, 2011 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, 2011 $	1st Quarter ended March 31, 2011 $	4th Quarter ended December 31, 2010 $	3rd Quarter ended September 30, 2010 $	2nd Quarter ended June 30, 2010 $	1st Quarter ended March 31, 2010 $	4th Quarter ended December 31, 2009 $	3rd Quarter ended September 30, 2009 $
							(2009 – Previous GAAP[1])	
Gross Revenues	1,816,000	1,584,000	1,529,000	2,534,000	2,676,000	1,347,000	1,346,000	1,056,000
Net loss for the period	(189,000)	(2,079,000)	(2,078,000)	(410,000)	(52,000)	(2,584,000)	(7,049,000)	(2,528,000)
Basic and diluted net loss per common share	(0.002)	(0.018)	(0.020)	(0.004)	(0.001)	(0.026)	(0.082)	(0.031)

(1) As Dejour's IFRS transition date was January 1, 2010, the 2009 comparative information has not been restated.

Fluctuations in quarterly revenues and net loss over the last eight quarters are due primarily to the volatility in oil and natural gas prices and changes in sales volumes due to production growth through successful drilling activity, principally in the Drake/Woodrush area. Increased revenues in the middle two quarters of 2010 reflected increasing production due to successfully brought two new wells into production. The loss for the quarter ending December 31, 2009, when compared with the other quarters, was the result of the recognition of an impairment loss of resource properties of $5,360,000 in the quarter.

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial instruments consist of cash and cash equivalents, accounts receivable, bridge loan, and accounts payable and accrued 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 to joint venture partners and 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, 2011, no accounts receivable has been deemed uncollectible or written off during the period.

(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 believes it has sufficient credit facilities to satisfy its financial obligations as they come due.

The Company's ongoing liquidity is impacted by various external events and conditions, including commodity price fluctuations and the global economic downturn.

(c) Commodity Price and Exchange Rate Volatility

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 actively 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, 2011.

The Company is also exposed to fluctuations in the exchange rate between the Canadian and U.S. dollar. 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, 2011.

FINANCIAL CONDITION, LIQUIDITY AND CAPITAL RESOURCES

Cash Balance and Cash Flow

The Company had cash and cash equivalents of $1,834,000 as at June 30, 2011. In addition to the cash balance, the Company also had accounts receivable of $1,175,000, most of which related to June 2011 oil and gas sales and had been received subsequent to June 30, 2011.

Our investing activities during the six months ended June 30, 2011 were financed primarily by the proceeds raised from the issuance of flow-through shares in December 2010 and the completion of a private placement in February 2011.

Bank Line of Credit and Bridge Loan Financing

During the year ended December 31, 2010, the bank line of credit of $850,000 was paid off in full in cash.

In March 2010, the Company negotiated a credit facility for a bridge loan of up to $5,000,000. This facility is secured by a first floating charge over all assets of DEAL, bears interest at 12% per annum. In April 2011, the Company extended the credit facility to October 31, 2011 and can be further extended for a maximum of 3 months subject to a 1% extension fee per month on the outstanding loan balance and lender's approval. Monthly repayment of $100,000 is required beginning May 31, 2011. This facility is used to support the development of its oil and gas properties in the Drake/Woodrush area. As at July 31, 2011, the outstanding balance of this credit facility was $4,200,000.

According to the terms of the facility, the Company is required to maintain certain loan covenants including working capital ratio, debt to equity ratio and debt to trailing cash flow ratio. As at June 30, 2011, the Company is in compliance with the debt to equity ratio requirement and breached the other two loan covenants, which had not been remedied subsequent to the period end. On July 25, 2011, the lender provided the Company with a letter to waive the June 30, 2011 covenant breaches.

Subsequent to June 30, 2011, the Company signed a Commitment Letter with a Canadian bank for a $7 million revolving operating demand loan to refinance the bridge loan and to provide operating funds. The operating loan 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.

Working Capital Position

As at June 30, 2011, the Company had a working capital deficit of $6,114,000. Excluding the non-cash warrant liability of $1,535,000 related to the fair value of US$ denominated warrants issued in previous equity financing, the cash working capital deficit was $4,579,000. The working capital deficit mainly consisted of $4.3 million bridge loan credit facility due on October 31, 2011. The Company plans to remedy the deficiency through the following:

- The Company intends to obtain a new credit facility to refinance during the second half of 2011, using a new reserve evaluation on its Woodrush property. Subsequent to June 30, 2011, the Company signed a Commitment Letter with a Canadian bank for a $7 million revolving operating demand loan to refinance the bridge loan and to provide general operating funds. The operating loan is at an interest rate of Prime + 1% (total 4% p.a. currently).

- Beginning in June 2011, oil production increased as a result of the waterflood at Woodrush. Oil production is expected to increase gradually during the remainder of 2011, 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 disposal of non-core asset or a combination of both.

Capital Resources

During the remainder of 2011, the Company plans to optimize the waterflood at Drake/Woodrush in Canada. A significant portion of the waterflood capital expenditures had already been spent in the first six months of 2011. Further capital expenditures at Drake/Woodrush and South Rangely during the remainder of 2011 are expected to be approximately $1,000,000.

Subsequent to June 30, 2011, the Company signed a Commitment Letter with a Canadian bank for a $7 million revolving operating demand loan to refinance the bridge loan and to provide operating funds. The operating loan is at an interest rate of Prime + 1% (total 4% p.a. currently). It can be used for capital expenditures for the remainder of 2011.

Also, the Company is pursuing debt or joint venture financing to fund its development at Gibson Gulch in the US.

Contractual Obligations

As of June 30, 2011, 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)	2011	2012	2013	2014	2015	Thereafter	Total
	$	$	$	$	$	$	$
Operating Lease Obligations	114	178	73	49	-	Nil	414
Bridge Loan	4,300	-	-	-	-	Nil	4,300
Total	4,414	178	73	49	-	Nil	4,714

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, 2011.

RELATED PARTY TRANSACTIONS

Except as disclosed elsewhere, during the six months ended June 30, 2011 and 2010, the Company entered into the following transactions with related parties:

a) Compensation awarded to key management included a total of salaries and consulting fees and share based payments of $941,050 (2010 - $901,948). 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, 2011 is $Nil (December 31, 2010 - $12,000 and January 1, 2010 - $Nil) owing to a company controlled by an officer of the Company.

b) The Company incurred a total of $2,301 (2010 - $137,099) in finance costs to a company controlled by an officer of the Company.

c) Included in interest and other income is $15,000 (2010 - $15,000) received from the companies controlled by officers of the Company for rental income.

d) In July 2008, Brownstone Ventures Inc. ("Brownstone") became a 28.53% working interest partner in the US properties. Brownstone owns more than 10% of outstanding common shares of the Company and one of the Brownstone's directors also serves on the board of directors of the Company. Included in accounts receivable at June 30, 2011 is $104,560 (December 31, 2010 - $168,771 and January 1, 2010 - $72,752) owing from Brownstone. Included in accounts payable and accrued liabilities at June 30, 2011 is $105,431 (December 31, 2010 - $Nil and January 1, 2010 - $Nil) owing to Brownstone.

e) In December 2009, a company controlled by the CEO of the Company ("HEC") became a 5% working interest partner in the Drake/Woodrush properties. Included in accounts receivable at June 30, 2011 is $11,610 (December 31, 2010 - $967 and January 1, 2010 - $Nil) owing from HEC. Included in accounts payable and accrued liabilities at June 30, 2011 is $9,513 (December 31, 2010 - $166,139 and January 1, 2010 - $63,679) owing to HEC.

f) In January 2011, the remaining balance of loan from HEC was repaid in full in cash (see Note 8 to the interim consolidated financial statements for details).

g) 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 12 to the interim consolidated financial statements for details).

These transactions are measured at the exchange amount established and agreed to by the related parties.

SUBSEQUENT EVENT

Subsequent to June 30, 2011, the Company signed a Commitment Letter with a Canadian bank for a $7 million revolving operating demand loan to refinance the bridge loan and to provide working capital. The operating loan 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.

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 interim consolidated financial statements for the three and six months ended June 30, 2011, including required comparative information, have been prepared in accordance with IFRS 1, *First-time Adoption of International Financial Reporting Standards*, and with International Accounting Standard ("IAS") 34, *Interim Financial Reporting*, as issued by the International Accounting Standards Board ("IASB"). Previously, the Company prepared its financial statements in accordance with Canadian GAAP. Unless otherwise noted, 2010 comparative financial statement information has been prepared in accordance with IFRS.

The adoption of IFRS has not had 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 Note 3 and Note 21 to the Company's Interim Consolidated Financial Statements for the three and six months ended June 30, 2011. The reconciliations include the Consolidated Balance Sheets as at January 1, 2010, June 30, 2010 and December 31, 2010, Consolidated Statement of Changes in Shareholders' Equity for the six and twelve months ended June 30, 2010 and December 31, 2010, respectively, and Consolidated Statements of Comprehensive Loss for the three and six months ended June 30, 2010 and the year ended December 31, 2010.

The following provides a summary of the significant IFRS accounting policy changes.

Exploration and Evaluation Assets

Under previous GAAP, the Company followed the Canadian Institute of Chartered Accountants ("CICA") guideline on full cost accounting in which all costs directly associated with the acquisition of, the exploration for, and the development of natural gas and crude oil reserves are capitalized on a country-by-country cost centre basis. Costs accumulated within each country cost centre were depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Under IFRS, the Company is required to adopt new accounting policies for its oil and gas activities, including pre-exploration costs, exploration and evaluation costs and development costs.

Under IFRS, exploration and evaluation ("E&E") costs are those expenditures for an area or project for which technical feasibility and commercial viability have not yet been determined. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proven reserves are determined to exist. Development ("D&P") costs include those expenditures for areas or projects where technical feasibility and commercial viability have been determined. Under previous GAAP, all costs, including E&E assets were capitalized as Property, Plant and Equipment ("PP&E"). Under IFRS, E&E costs and PP&E are disclosed as different class of assets.

Impairment

Under previous GAAP, the Company was required to recognize an impairment loss if the carrying amount exceeds the undiscounted cash flows from proved reserves for the country cost centre. If an impairment loss was to be recognized, it was then measured as the amount that the carrying value exceeded the sum of the estimated fair value of the proved and probable reserves and the costs of unproved properties. Impairments recognized under previous GAAP could not be reversed.

Under IFRS, the Company is required to recognize and measure an impairment loss if the carrying value exceeds the recoverable amount for a cash-generating unit ("CGU"). Oil and gas assets are grouped into CGUs based on their ability to generate largely independent cash flows. Under IFRS, the recoverable amount is the higher of the estimated fair value less cost to sell and value in use. Impairment losses, other than goodwill, can be reversed when there is a subsequent increase in the recoverable amount.

Upon adoption of IFRS, the Company recognized an additional impairment charge of $14.7 million to the opening deficit at January 1, 2010, relating to certain non-core E&E assets in the US. The impairment charge was based on the difference between the net book value of the assets and the estimated recoverable amount. The recoverable amount was determined using the fair value less costs to sell based on the expected amount for which the asset could be sold in an arm's length transaction. Under previous GAAP, these assets were included in the US country cost centre ceiling test, which was not impaired as at December 31, 2009.

Warrant Liabilities

The Company issued US$ denominated warrants as part of equity financings, while the Company's functional currency is the CAD$. Under previous GAAP, common share purchase warrants were classified as equity.

Under IFRS, the Company determined that the warrants denominated in US$ outstanding at the date of transition must be treated as warrant liabilities in the Company's statement of financial position. Any issuance costs related to the warrants denominated in a foreign currency are expensed upon initial issuance. Prospectively, these warrants are re-measured at each balance sheet date based on estimated fair value, and any resultant changes in fair value are recorded as non-cash valuation adjustments as income or loss in the respective period.

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, 2011. 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, 2011 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, 2011, 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 Canadian GAAP.

For the year ended December 31, 2010, the Company considered its ICFR and identified that such controls did not operate effectively during the period with the result that misstatements were not prevented or detected in the interim financial statements for the six months ended June 30, 2010. Specifically, period end review of the interim financial statements by management did not identify the understatement of depletion on the oil and gas properties and the future income tax effects associated with the flow-through funds that were renounced to investors during the period. Such financial statements were subsequently restated and refiled. These restatements have no impact on the cashflow or cash position of the Company.

During 2011, the Company had improved staff training and period end review process. The Company has also engaged external consultants to assist in complex accounting matters including IFRS conversion adjustments. With the improvement in operation of these controls, the Company believes it has mitigated the control weaknesses identified in 2010.

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.

The Board of Directors, through its Audit Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Audit Committee is composed of three 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

Within the MD&A references are made to terms commonly used in the oil and gas industry.

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

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

EBITDA is a non-GAAP measure defined as net income (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.

Certain measures in this document do not have any standardized meaning as prescribed by Canadian GAAP such as Operating Cash Flow, Operating Netback, 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.

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 which are not historical facts are forward-looking statements that involve risks, uncertainties and other factors that could cause actual results to differ materially from those expressed or implied by such forward looking statements. Factors that could cause such differences include, but not limited to, are volatility and sensitivity to market price for uranium, environmental and safety issues including increased regulatory burdens, possible change in political support for nuclear energy, changes in government regulations and policies, and significant changes in the supply-demand fundamentals for uranium that could negatively affect prices. Although the Company believes that the assumptions inherent in forward looking statements are reasonable we recommend that one should not rely heavily on these statements. The Company disclaims any intention or obligation to update or revise any forward looking statements whether as a result of new information, future events or otherwise.

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
Mcfe	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.