DEJOUR ENTERPRISES LTD.
ENERGY. INDEPENDENCE.

MANAGEMENT DISCUSSION AND ANALYSIS

For the Year Ended December 31, 2009

Date of Report: March 30, 2010

The following is a discussion of the consolidated operating results and financial position of Dejour Enterprises Ltd. (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 for the year ended December 31, 2009.

All financial information in this Management's Discussion and Analysis ("MD&A") is expressed and prepared in accordance with the Canadian generally accepted accounting principles. All references are 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

Dejour emerged from 2009 a much stronger Company than it entered. The contraction in the global financial markets and falling commodity prices witnessed in late 2008 and early 2009 created a profound shift in the business environment. This shift, coupled with the royalty regime changes in the Province of Alberta caused the Company to make changes in its business strategy and expectations for near term growth. As 2009 progressed, the Company eliminated all non essential expenses, sold some non strategic assets in Canada and raised equity in an adverse market. These activities were all undertaken to protect the value of the Company's core assets and allow the Company to proceed with its business plan as commodity prices strengthen.

As 2010 begins, oil prices have stabilized around US$80/barrel and many in the industry are seeing signs that the gas market is returning to a supply demand balance. The Company now believes that this is the time to move forward on the development of our key Piceance Basin acreage. Under moderate commodity prices forecasts of US$80/barrel for oil and US$6/Million BTU's for natural gas, we believe that our major projects are sufficiently robust to attract competitive financing, allowing us to undertake important investments in the growth of the Company in 2010 and 2011 without significant dilution of the value of the projects.

As we move into 2010, we are witnessing a return to a much more favorable growth environment, perhaps best illustrated by the increase in the Company's Net Proved and Probable Reserves which climbed from approximately 6 BCFE as at December 31, 2008 to over 217 BCFE as at December 31, 2009. A very significant reserve and value increase for the Company resulting directly from the actions taken to preserve the company core assets in 2009.

In 2010, we anticipate an improving business environment and improving conditions in the financial markets for the Company and its projects. Company growth over the next one to two years will come from exploiting development opportunities at Drake/Woodrush property and from the development of low risk, high value resource plays identified in the Montney in northwestern British Columbia and in select Piceance Basin properties.

The Company's business objective remains the economic development of key projects and growth opportunities, resulting in the enhancement of shareholder value. This will be accomplished through prudent investment in and management of the Company's portfolio of producing and non producing assets, combined with a limited program of strategic acquisitions and divestitures in our core operating areas.

COMPANY OVERVIEW

The Company's 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 130,000 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

In Q2 2008, the Company commenced production and started receiving revenue from its Peace River Arch oil & gas properties, realizing the shift from a pure play exploration company to an exploration and production company.

2009 HIGHLIGHTS

In 2009, the Company's focus was on the restructuring of current assets and operations to reduce debt and lower operating costs while maintaining all prospective acreage holdings and positioning for renewed drilling activities as both the business environment and commodity prices improved.

Despite the difficult environment faced in 2009, the Company was able to achieve all major objectives and also make significant progress on key strategic initiatives that resulted in:

1. Increased Net Proved and Probable Reserves by more than 3,500% from slightly more than 6 BCFE to over 217 BCFE. The before tax discounted net present value 10% (NPV10) of the companies proved and probable reserves, net of all future costs for development is now valued at $324 million. This is up from $31 million as at December 31, 2008. The major increase in reserves results from developments in the Gibson Gulch field in the Piceance Basin where the Company holds a 72% working interest in 2200 gross acres. This property is discussed in more detail later in this analysis.

2. Reduced debt from $18.3 million to $6.2 million

3. Eliminated working capital deficit of $12.7 million as at December 31, 2008 and resulted in a positive working capital of $410,000 as at December 31, 2009

4. Raised $5 million in equity under challenging market conditions, allowing the Company to execute its winter drilling program in Woodrush Field.

5. Strengthening our Board of Directors with the addition of Stephen Mut as Co-Chairman of the Board and Darren Devine as Director.

OIL AND GAS EXPLORATION AND PRODUCTION

Over the 2008 and 2009 time frame the Company has evolved its forward focus from acquiring resource potential toward 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.

US Activities

Gibson Gulch

The Company has moved forward aggressively to begin the process of bringing 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 thick columns 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 mid 2011 with production to begin later in that year. Subsequent to December 31, 2009, 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

Over 2009, Dejour developed a plan for evaluation and subsequent exploitation of an oil prospect at South Rangely. During 2010, the Company plans to drill 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 robust 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.

Roan Creek

South and west of Gibson Gulch, Dejour owns 72% of the 1400+ acre Roan Creek evaluation project. This gas prone 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 as Roan Creek will be somewhat thinner than is found to the east and west, Roan Creek has significant 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 to be conducted in late 2010 or early 2011. Success at Roan Creek is expected to make some 3,000+ additional acres currently held by the Company prospective.

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's 109,400 net acre position was sculpted over the 2006-2008 period. Dejour is operator of approximately 130,000 acres and is a non-operator in another 110,000 acres where Retamco Operating Inc. and Fidelity Exploration and Production Company operate.

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 7,300 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.
- Greentown - This 15,000 acre (gross) prospect in the Uinta Basin in eastern Utah has significant oil potential as evidenced by drilling success encountered by Delta Petroleum in 2008. This area remains technically challenging due to issues associated with salt layers overlaying the target zone.

These potential developments will continue to be matured over 2010 with exploration or evaluation drilling scheduled for 2011/2012. Exploitation of these opportunities will in all likelihood proceed only after developments at Gibson Gulch, South Rangely and Roan Creek reach equilibrium stage.

Significant amounts of very prospective acreage are located throughout the remainder of Dejour's land holdings. These positions, which were identified during studies conducted during 2008 and 2009, will be high graded over the years of 2010 to 2012 so that exploration and appraisal drilling programs can be developed for the middle part of the decade. If during further studies, certain acreage is deemed to have exceptional potential, it is possible for that acreage to leap the queue and assume a higher priority status than it currently enjoys.

Summary of Capitalized US Oil and Gas Expenditures

A continuity summary of capitalized acquisition costs, exploration expenditures in the Company's US oil and gas properties for the year ended December 31, 2009 are as follows:

	December 31, 2008	December 31 2009		
	Net Book Value	**Net Expenditures**	**Write-off**	**Net Book Value**
US Oil and Gas Properties				
Colorado/Utah Projects				
Acquisition	$ 29,325,724	$ 193,892	$ (1,403,929)	$ 28,115,687
Geological and geophysical	-	19,186	-	19,186
Capitalized general and administrative	-	313,577	-	313,577
	29,325,724	526,655	(1,403,929)	28,448,450
Others				
Acquisition	167,674	-	-	167,674
	167,674	-	-	167,674
Total US Oil and Gas Properties	**$ 29,493,398**	**$ 526,655**	**$ (1,403,929)**	**$ 28,616,124**

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.

In 2009, production from Dejour operated wells averaged about 456 BOE/D (202 BOPD of oil and natural gas liquids and 1,524 MCFD of gas). At year end, gas production was limited due to restrictions imposed by a third party providing compression services. December production averaged 277 BOE/D (122 BOPD of oil and 930 MCFD of gas).

As at December 31, 2009, DEAL's holdings totaled 20,247 net acres concentrated in the Peace River Arch and the Montney shale basin.

Production and Development Projects

Woodrush/Drake

After completing a comprehensive study of the Woodrush/Drake area in 2009, Dejour determined that the area presented significant room for value increase. Per the recommendations of that study, the Company implemented a five point program which included:

- Operating cost reduction
- Production increase from existing wells
- Acquisition of additional prospective acreage
- Seismic data acquisition and analysis
- Step-out drilling from existing production based on seismic data.

During the second half of the year, DEAL made personnel and field management changes to reduce costs. Key to this program was the installation of a more cost effective gas compression system. Production from wells were temporarily shut in due to low gas prices and returned to service when commodity prices improved.

DEAL was the successful bidder for 1,579 net acres of Crown land located adjacent to the northern boundary of the Woodrush lease which was offered for lease in November 2009. The price paid for this acquisition was approximately $340,000.

Late in 2009, the Company began preparations for a 3-D seismic survey designed to investigate the northern portion of the Woodrush lease and the southern portion of the newly acquired acreage. The survey was shot, processed and interpreted in late 2009/early 2010 with several drilling locations identified. Rigs were contracted and two or three wells are anticipated to be drilled before activity is truncated at time of "break-up" in the water prone areas which overlay the prospective oil and gas deposits.

In late 2009 and prior to the seismic survey, DEAL drilled, sidetracked and suspended an oil and gas well with hydrocarbon shows in several intervals. The well location was based upon previously acquired seismic data.

During 2009, DEAL sold 25% of its interest in Woodrush/Drake for $4,500,000 in cash. Funds from the sale of the interest were used to fund expanded Woodrush/Drake investments and to reduce the Company's outstanding bank line of credit. DEAL's working interest in Woodrush/Drake was 75% as at December 31, 2009.

Subsequent to December 31, 2009, DEAL installed gas compression facilities at Woodrush that eliminated third party restrictions and lowered compression costs. By mid-March 2010, Dejour's net 75% production had climbed to 465 BOE/D (120 BOPD and 2,100 MCFD). In the second half of March, DEAL drilled, completed and tested two additional wells at Woodrush. The first well was productive in the Gething formation and tested at a rate in excess of gross 900 MCFD (net 675 MCFD) of natural gas. The second well was productive in the Halfway formation and tested at a rate in excess of gross 500 BOPD (net 375 BOPD) of oil. These wells will be tied into production early in Q2 2010.

Carson Creek

In June 2009, DEAL completed the sale of its 100% working interest in Carson Creek to an unrelated third party for $2,100,000.

Buick Creek (Montney Shale Basin)

DEAL acquired 6,352 gross and net acres in the emerging Montney natural gas resource play in northeastern British Columbia during 2008. In early 2009, the Company also acquired an existing wellbore which the Company believes can be used for re-entry and testing of the play.

Summary of Capitalized Canadian Oil and Gas Expenditures

A continuity summary of capitalized acquisition costs, exploration expenditures in the Company's Canadian oil and gas properties for the year ended December 31, 2009 is as follows:

	December 31, 2008	December 31, 2009		
	Net Book Value	**Expenditures (Dispositions), Net**	**Write-off / Depletion**	**Net Book Value**
Canadian Oil and Gas Properties				
Carson Creek				
Land acquisition and retention	$ 265	$ (265)	$ -	$ -
Drilling and completion	996,753	(996,753)	-	-
Equipping and facilities	760,613	(760,613)	-	-
Geological and geophysical	13,364	(13,364)	-	-
Capitalized general and administrative	16,883	(16,883)	-	-
	1,787,878	(1,787,878)	-	-
Drake/Woodrush				
Land acquisition and retention	655,601	(269,491)	-	386,110
Drilling and completion	5,804,790	(521,295)	-	5,283,495
Equipping and facilities	11,945,442	(1,830,494)	-	10,114,948
Geological and geophysical	356,308	98,648	-	454,956
Capitalized general and administrative	253,240	13,568	-	266,808
	19,015,381	(2,509,064)	-	16,506,317
Montney				
Land acquisition and retention	907,733	(80,660)	-	827,073
Capitalized interest	69,317	10,919	-	80,236
Capitalized general and administrative	-	8,473		8,473
	977,050	(61,268)	-	915,782
Saddle Hills				
Land acquisition and retention	3,871	1,077	-	4,948
Drilling and completion	885,319	2,583	-	887,902
Equipping and facilities	19,540	35,031	-	54,571
Geological and geophysical	78,407	-	-	78,407
Capitalized general and administrative	-	2,164		2,164
	987,137	40,855	-	1,027,992
Others				
Land acquisition and retention	860,387	762,790	-	1,623,177
Drilling and completion	5,547,586	(1,127,441)	-	4,420,145
Equipping and facilities	182,119	301,976	-	484,095
Geological and geophysical	1,003,554	(51,024)	-	952,530
Capitalized general and administrative	363,703	39,092	-	402,795
	7,957,349	(74,607)	-	7,882,742
Corporate Costs				
Assets retirement obligation	404,311	-	(154,160)	250,151
Depletion	(3,635,777)	-	(6,382,574)	(10,018,351)
Impairment	-	-	(3,955,854)	(3,955,854)
	(3,231,466)	- -	(10,492,588) -	(13,724,054)
Total Canadian Oil and Gas Properties	**$ 27,493,329**	**$ (4,391,962)**	**$ (10,492,588)**	**$ 12,608,779**

The following table summarizes the breakdown of capital expenditures net of dispositions by type for the years ended December 31, 2009 and 2008:

		December 31 2009		December 31 2008
Land acquisition and retention	$	607,342	$	4,884,355
Drilling and completion		(2,642,906)		8,498,370
Equipping and facilities		(2,254,099)		12,859,693
Geological and geophysical		53,446		461,952
Capitalized general and administrative		359,991		759,949
Capitalized interest		10,919		69,317
	$	(3,865,307)	$	27,533,636

Daily Production

	December 31 2009	December 31 2008
By Product		
Natural gas (mcf/d)	**1,524**	1,395
Natural gas liquids (bbls/d)	**4**	2
Oil (bbls/d)	**198**	22
Total (boe/d)	**456**	256

Despite the sale of some of our assets, annual production for 2009 averaged 456 BOE/D, an increase of 78% compared to 2008. An increase was primarily the result of increasing production at Woodrush.

URANIUM EXPLORATION PROJECTS

During the year ended December 31, 2009, the Company sold 16,750,000 shares of Titan Uranium Inc. for proceeds of $2,305,491, but maintains its 10% carried interest and 1% Net Smelter Return on approximately 578,365 acres. During the year ended December 31, 2009, a number of leases expired. As a result, the Company recorded an impairment of uranium properties of $148,906. The carrying values of the Company’s 10% carried interests were $533,085 as at December 31, 2009 and $696,991 as at December 31, 2008.

SELECTED ANNUAL INFORMATION

The following table set forth consolidated financial data prepared in accordance with Canadian GAAP for our last three fiscal years:

(in thousands of dollars except per share amounts)	For the Years Ended December 31		
	2009	2008	2007
	$	$	$
Revenues	6,786	5,766	-
Net loss	(12,807)	(20,891)	(26,811)
Loss per common share, basic and diluted	(0.16)	(0.29)	(0.40)
Total assets	45,886	62,643	63,143

The Company has not declared any cash dividends since inception.

SHARE CAPITAL

The following is a summary of share transactions for the years ended December 31, 2009 and 2008:

Authorized: Unlimited common shares
Unlimited first preferred shares, issuable in series
Unlimited second preferred shares, issuable in series

	Common Shares	Value
Balance at December 31, 2007	70,128,329	$ 61,393,964
- For conversion of convertible debenture	884,242	1,214,497
- For cash on exercise of stock options	1,681,048	887,621
- For cash on exercise of warrants	958,263	1,447,464
- Contributed surplus reallocated on exercise of stock options	-	532,531
- Renounced flow through share expenditures	-	(536,900)
Balance at December 31, 2008	73,651,882	64,939,177
- For cash on exercise of stock options	631,856	273,223
- For settlement of debt	8,030,303	2,650,000
- For cash by private placements, net of share issuance costs	13,476,997	4,549,882
- Contributed surplus reallocated on exercise of stock options	-	147,222
Balance at December 31, 2009	95,791,038	$ 72,559,504

As at March 30, 2010, the Company had 98,698,372 issued and outstanding common shares.

STOCK OPTIONS AND SHARE PURCHASE WARRANTS

The following table summarizes information about stock option transactions:

	Outstanding Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
Balance, December 31, 2007	5,627,481	$ 1.49	1.96 years
Options granted	4,945,000	0.88	
Options exercised	(1,681,048)	0.53	
Options cancelled and expired	(1,693,053)	1.83	
Balance, December 31, 2008	7,198,380	1.22	2.94 years
Options granted	3,312,000	0.46	
Options exercised	(631,856)	0.43	
Options cancelled and expired	(5,461,842)	1.46	
Balance, December 31, 2009	4,416,682	$ 0.45	3.54 years

Details of stock options vested and exercisable as at December 31, 2009 are as follows:

Number of Options Outstanding and vested	Exercise Price	Weighted Average Remaining Contractual Life (Years)
1,095,625	$ 0.450	3.00
60,000	0.500	1.00
78,182	0.550	1.00
1,233,807	$ 0.459	2.78

As at December 31, 2009, no outstanding and vested options were “in the money” (the exercise price was more than the market trading price).

STOCK OPTIONS AND SHARE PURCHASE WARRANTS (continued)

The following table summarizes information about share purchase warrants:

	Outstanding Warrants	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
Balance, December 31, 2007	2,372,531	$ 3.15	1.31 years
Warrants issued	884,242	1.53	
Warrants exercised	(958,263)	1.53	
Warrants expired	(194,381)	1.53	
Balance, December 31, 2008	2,104,129	3.35	0.40 years
Warrants issued	14,736,150	0.47	
Warrants exercised	-	-	
Warrants expired	(2,104,129)	3.35	
Balance, December 31, 2009	14,736,150	$ 0.47	4.36 years

Details of warrants outstanding as at December 31, 2009 are as follows:

Number of Warrants Outstanding	Exercise Price	Weighted Average Remaining Contractual Life (Years)
2,000,000	$ 0.50	1.47
4,015,151	$ 0.55	4.48
8,075,000	US$0.40	4.98
645,999	US$0.46	4.84
14,736,150		

Subsequent to the year-end, the Company granted a total of 3,053,000 incentive stock options with an exercise price of $0.35 per share to its independent directors, management, officers, employees and consultants and issued 1,491,090 share purchase warrants with an exercise price of CAD$0.45 per warrant.

RELATED PARTY TRANSACTIONS

During the years ended December 31, 2009 and 2008, the Company entered into the following transactions with related parties:

a) The Company incurred a total of $682,619 (2008 - $737,112) in consulting and professional fees and a total of $90,714 (2008 - $111,291) in rent expenses to the companies controlled by the officers of the Company. Included in the total consulting and professional fees incurred during fiscal 2009 was a payment of $107,000 made to a former officer of the Company to terminate the consulting agreement with this officer.

b) The Company incurred a total of $382,748 (2008 - $300,434) in interest expense and finance fee to the related parties.

c) The Company received total rental income of $30,000 (2008 - $28,700) from the companies controlled by the officers of the Company.

d) The Company received total consulting fee income of $114,200 (2008:Nil) from a related party.

e) In May 2008, DEAL issued a promissory note for up to $2,000,000 to Hodgkinson Equity Corporation ("HEC"). As at December 31, 2008, $1,950,000 had been advanced on the promissory note. During the year ended December 31, 2009, $150,000 was repaid and the remaining $1,800,000 was assumed by the Company. Pursuant to an agreement with HEC, $450,000 of the debt was restructured, $450,000 of the debt was converted into common shares and common share purchase warrants of the Company, and the remaining $900,000 was settled by the sale of 5% working interest in Drake/Woodrush to HEC.

f) In August 2008, the Company borrowed $600,000 from HEC. This was fully paid off during the year ended December 31, 2009.

g) In February 2009, HEC exercised its option and elected to become a 10% working interest partner in DEAL's Montney (Buick Creek) property. The option price was $90,642.

These transactions are in the normal course of operations and are measured at the exchange amount established and agreed to by the related parties.

RESULTS OF OPERATIONS – YEARS ENDED DECEMBER 31, 2009 AND 2008

Summary of Operational Highlights

DEAL Production and Netback Summary

	2009	2008
Production Volumes:		
Oil (bbls)	72,254	8,058
Gas (mcf)	566,158	509,034
Natural gas liquids (bbls)	2,028	764
Total (BOE)	166,353	93,661
Average Price Received:		
Oil ($/bbls)	54.67	55.21
Gas ($/mcf)	4.35	9.48
Natural gas liquids ($/bbls)	52.91	110.90
Total ($/BOE)	38.92	57.16
Royalties ($/BOE)	3.42	12.26
Operating Expenses ($/BOE)	17.72	19.41
Netbacks ($/BOE)	17.95	25.49

Revenues

	December 31 2009	December 31 2008
Revenue		
Natural gas	**$ 2,413,026**	$ 4,962,614
Oil	**3,964,512**	703,167
Natural gas liquids	**93,187**	99,774
Total oil and gas revenue	**6,470,725**	5,765,555
Realized financial instrument gain	**315,270**	-
Total revenue	**$ 6,785,995**	$ 5,765,555

For the year ended December 31, 2009 ("fiscal 2009"), the Company recorded $4,058,000 in crude oil and natural gas liquids sales and $2,413,000 in natural gas sales as compared to $803,000 in crude oil and natural gas liquids sales and $4,963,000 in natural gas sales for the year ended December 31, 2008 ("fiscal 2008"). In 2008, the Company only had nine months of production, as the Company commenced production in April 2008.

The following table summarizes the commodity prices realized by the Company and the crude oil and natural gas benchmark prices for the years ended December 31, 2009 and December 31, 2008:

	December 31 2009	December 31 2008
Dejour Average Prices		
Natural gas ($/mcf)	**$ 4.35**	$ 9.48
Oil ($/bbl)	**54.67**	55.21
Natural gas liquids ($/boe)	**52.91**	110.90
Total average price ($/boe)	**$ 38.92**	$ 57.16
Benchmark Pricing		
Western Canadian Select (WCS) ($/bbl)	**52.43**	79.70
Natural gas - AECO-C Spot ($ per mcf)	**$ 4.14**	$ 8.13

Average natural gas sales prices decreased 54% to $4.35 per mcf in the fiscal 2009, compared to $9.48 per mcf in fiscal 2008. During fiscal 2009, AECO-C daily spot prices for natural gas decreased 49% compared to fiscal 2008. This decrease reflects the ongoing concern of an oversupply in natural gas markets.

Oil prices received for fiscal 2009 were $54.67 per barrel ("bbl"), which were comparable to the prices received for fiscal 2008. The price realized for natural gas liquids in fiscal 2009 was $52.91 per bbl, a decrease of 52% from $110.90 per bbl in fiscal 2008. Natural gas liquids prices have declined substantially, as the worldwide economic slowdown has reduced demand for commodities.

Royalties

	December 31 2009	December 31 2008
Royalties		
Crown	**$ 252,028**	$ 809,884
Freehold and GORR	**317,448**	338,771
Total royalties	**$ 569,476**	$ 1,148,655
$ per boe	**$ 3.42**	$ 12.26
As a percentage of oil and gas revenue	**9%**	20%

Royalties for fiscal 2009 were $569,000 or $3.42 per BOE as compared to $1,149,000 or $12.26 per BOE for fiscal 2008. In 2009, the Company was approved for a Crown royalty holiday and therefore, no royalty was payable on revenue from the first 72,000 bbl of oil production. The lower natural gas price also resulted in lower royalty %, as Crown royalty is a function of price and volume.

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 fiscal 2009 were $2,915,000 or $17.52 per BOE as compared to $1,973,000 or $21.07 per BOE for fiscal 2008. The increase in total expenses was primarily due higher production volume. On a per BOE basis, operating and transportation expenses decreased as the Company gained efficiency in managing the operation.

General and Administrative Expenses

General and administrative expenses decreased to $4,038,000 for fiscal 2009 from $4,215,000 for fiscal 2008. The decrease was primarily due to the reduction of $570,000 and $186,000 in investor relation expenses and travel expenses respectively. During the year, the Company restructured the Calgary office and reduced overhead. Offsetting the costs reduction in 2009 was an increase in legal fees to settle a termination claim litigation cost from a former officer and director and some restructuring charges.

Interest and Finance Fees

For fiscal 2009, the Company recorded interest and finance fees of $818,000, compared to $481,000 for fiscal 2008. The increase is due to higher loan fee and interest paid to bank on its revolving operating loan facility obtained in August 2008 and loan interest paid to Brownstone Ventures Inc. The loan was obtained from Brownstone in June 2008 to acquire additional acreage in the US property.

Amortization, Depletion and Accretion

For fiscal 2009, amortization and depletion of property and equipment and accretion of asset retirement obligations was $6,437,000 compared to $3,691,000 for fiscal 2008. The increase was due to the commencement of oil and gas production in April 2008.

Stock Based Compensation

For fiscal 2009, the Company recorded non-cash stock based compensation expense of $697,000 compared to $2,720,000 for fiscal 2008. The decrease in stock based compensation expense was because many of the stock options previously granted had been fully vested.

Income Taxes, Foreign Exchange Gain (Loss) and Other Items

Future income tax recovery for fiscal 2009 was $1,133,000, as compared to future income tax expenses of $596,000 for fiscal 2008. As at December 31, 2009, the Company had unrecognized future income tax assets relating to loss carry forwards and the excess of the value of the tax pools for the oil and gas properties over the accounting net book value, as compared to having a future income tax liability balance as at December 31, 2008, which resulted in future income tax recovery for the current fiscal year.

At the end of 2008, the Company had a US$3,800,000 loan from a related party. Due to the decline in the value of US$, foreign exchange gain in 2009 was $257,000 compared to a foreign exchange loss of $676,000 in 2008.

Impairment of Oil & Gas Properties

The impairment loss of oil and gas properties for fiscal 2009 totaled $5,360,000, compared to $2,030,000 in 2008. During 2009 and 2008, the Company wrote off certain non-core acreages in the US that expired and recorded an impairment loss of $1,404,000 and $2,030,000 respectively.

In addition, the Company recorded an impairment loss of $3,956,000 related to the excess of the carrying value of Canadian oil and gas properties over its fair value as at December 31, 2009 based on an independent reserve evaluation report. Most of the impairment of carrying relates to non-core assets that were abandoned or sold.

Subsequent to the 2009 year-end, the Company drilled two successful wells, which were not included in the December 31, 2009 reserve evaluation report for determining the fair value of Canadian oil & gas properties.

Net Loss

The Company's net loss for fiscal 2009 was $12,807,000 or $0.16 per share, compared to a net loss of $20,891,000, or $0.29 per share for fiscal 2008. In 2008, the Company had a non-cash impairment loss of $12,990,000 on investment in Titan, offset by an equity income from Titan of $3,637,000. In 2009, the Company disposed of all its investment in Titan and equity loss was only $142,000. The equity loss from Titan relates to the Company's proportionate share of Titan's loss in the year.

RESULTS OF OPERATIONS – THREE MONTHS ENDED DECEMBER 31, 2009 AND 2008

Summary of Operational Highlights

DEAL Production and Netback Summary

	Three Months Ended December 31, 2009	Three Months Ended December 31, 2008
Production Volumes:		
Oil (bbls)	13,995	7,457
Gas (mcf)	89,082	155,552
Natural gas liquids (bbls)	111	155
Total (BOE)	28,842	33,538
Average Price Received:		
Oil ($/bbls)	63.96	51.70
Gas ($/mcf)	4.19	7.55
Natural gas liquids ($/bbls)	78.00	33.07
Total ($/BOE)	44.28	46.67
Royalties ($/BOE)	2.18	8.76
Operating Expenses ($/BOE)	11.43	26.06
Netbacks ($/BOE)	30.75	11.85

Revenues

		Three months ended December 31, 2009		Three months ended December 31, 2008
Revenue				
Natural gas	$	**430,422**	$	1,209,687
Oil		**909,233**		643,795
Total oil and gas revenue		**1,339,655**		1,853,482
Realized financial instrument gain		**5,846**		-
Total revenue	$	**1,345,501**	$	1,853,482

For the three months ended December 31, 2009 ("Q4 2009"), the Company recorded $909,000 in crude oil sales and $431,000 in natural gas sales as compared to $644,000 in crude oil sales and $1,210,000 in natural gas sales for the three months ended December 31, 2008 ("Q4 2008"). The decrease in revenues for Q4 2009 over Q4 2008 was due to a combination of significantly lower natural gas and natural gas liquids prices in Q4 2009 and lower gas production as one of the gas wells was shut-in in Q4 2009.

Royalties

		Three months ended December 31, 2009		Three months ended December 31, 2008
Royalties				
Crown	**$**	**34,042**	$	200,310
Freehold and GORR		**28,904**		91,487
Total royalties	**$**	**62,946**	$	291,797
$ per boe	**$**	**2.18**	$	8.70
As a percentage of oil and gas revenue		**5%**		16%

Royalties for Q4 2009 and Q4 2008 were $63,000 or $2.18 per BOE as compared to $292,000 or $8.70 per BOE respectively. In 2009, the Company was approved for a Crown royalty holiday and therefore, no royalty was payable on revenue from the first 72,000 bbl of oil production. The lower natural gas price also resulted in lower royalty %, as Crown royalty is a function of price and volume.

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 Q4 2009 were $390,000 or $13.52 per BOE as compared to $908,000 or $27.07 per BOE for Q4 2008. The decrease was mainly due to the lower gas production for the current quarter. Operating and transportation expense per BOE decreased in Q4 2010 as the Company gained efficiency in managing its operation.

General and Administrative Expenses

General and administrative expenses for Q4 2009 were $1,203,000, compared to $504,000 for Q4 2008. The increase in professional fees was mainly the result of the legal fees incurred associated with the termination claim and litigation from a former officer and director. In addition, in Q4 2008, the Company did a year-end adjustment to capitalize certain consulting and engineering costs for 2008 into oil & gas properties. In 2009, the Company started capitalizing those costs quarterly instead of at the end of the year.

Interest and Finance Fees

For Q4 2009, the Company recorded interest and finance fees of $158,000, compared to $188,000 for Q4 2008. The decrease was primarily the result of lower balance on loans from related parties.

Amortization, Depletion and Accretion

Amortization and depletion of property and equipment and accretion of asset retirement obligations was $904,000 for Q4 2009 compared to $1,499,000 for Q4 2008. The decrease was due to the lower gas production for the current quarter.

Stock Based Compensation

For Q4 2009, the Company recorded non-cash stock based compensation expense of $198,000 compared to $480,000 for Q4 2008. The decrease in stock based compensation expense was because many of the stock options previously granted had been fully vested.

Income Taxes, Foreign Exchange and Other Items

Future income tax expense for Q4 2009 was $nil, as compared to $1,217,000 for Q4 2008. The future income tax expense for Q4 2008 was a result of the future income tax liability, which arose because the accounting net book value assigned to the oil and gas properties was in excess of the value of the tax pools.

Foreign exchange loss was decreased by $458,000 to $131,000 for Q4 2009 from $589,000 for Q4 2008. At the end of 2008, the Company had a US$3,800,000 loan from a related party and recorded a foreign exchange loss due to higher US dollars. In June 2009, this loan was converted to a Canadian dollar denominated loan and no foreign currency revaluation was necessary for this loan in 2009 Q4.

Impairment of Oil & Gas Properties

The impairment loss of oil and gas properties for the current quarter totaled $5,360,000, compared to $2,030,000 for Q4 2008. During Q4 2009 and Q4 2008, the Company wrote off certain non-core acreages in the US that expired and recorded an impairment loss of $1,404,000 and $2,030,000 respectively.

In Q4 2009, the Company recorded an impairment loss of $3,956,000 related to the excess of the carrying value of Canadian oil and gas properties over its fair value as at December 31, 2009 based on an independent reserve evaluation report. Most of the impairment of carrying relates to non-core assets that were abandoned or sold.

Subsequent to the 2009 year-end, the Company drilled two successful wells, which were not included in the December 31, 2009 reserve evaluation report for determining the fair value of Canadian oil & gas properties.

Net Loss and Other Items

The Company's net loss for Q4 2009 was $7,049,000 or $0.08 per share, compared to a net loss of $15,151,000 or $0.21 per share for Q4 2008. In Q4 2008, the Company had a non-cash impairment loss of $12,990,000 on its investment in Titan and this was offset by an equity income from Titan of $3,637,000. In 2009, the Company disposed of all its investment in Titan and there was no equity loss in Q4 2009. The equity income from Titan relates to the Company's proportionate share of Titan's income in the period.

SUMMARY OF QUARTERLY RESULTS

The following summary for the eight most recently completed financial quarters ending December 31, 2009 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.

	4th Quarter ended December 31, 2009 $	3rd Quarter ended September 30, 2009 $	2nd Quarter ended June 30, 2009 $	1st Quarter ended March 31, 2009 $	4th Quarter ended December 31, 2008 $	3rd Quarter ended September 30, 2008 $	2nd Quarter ended June 30, 2008 $	1st Quarter ended March 31, 2008 $
Revenues	1,345,501	1,056,312	1,682,195	2,701,987	1,853,482	1,677,513	2,234,560	-
Net loss for the period	(7,048,949)	(2,528,039)	(780,872)	(2,449,058)	(15,151,051)	(3,038,792)	(1,143,679)	(1,557,231)
Basic and diluted net loss per common share	(0.08)	(0.03)	(0.01)	(0.03)	(0.21)	(0.04)	(0.02)	(0.02)

The significant increase in revenues in the 2nd quarter of 2008 to 4th quarter of 2009 was due to the commencement of oil and gas production in April 2008.

The substantial loss for the current quarter, when compared with the other quarters, was the result of the recognition of an impairment loss of oil and gas properties of $5,360,000 in the quarter. In addition, the substantial loss for the quarter ending December 31, 2008, when compared with the other quarters, was due to the recognition of an impairment loss of $12,990,343 for the investment in Titan in the quarter.

FINANCIAL INSTRUMENTS

The Company's financial instruments consist of cash and cash equivalents, accounts receivable, bank indebtedness and line of credit, accounts payable, and loans from related party and working interest partner. 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.

As at December 31, 2009, the Company had outstanding a natural gas derivatives contract for 600 gigajoules ("GJ") per day for the period from November 1, 2009 to April 30, 2010. This contract consisted of a CAD$4.47 per GJ forward sale agreement. As at December 31, 2009, the Company also had outstanding a crude oil derivatives contract for 100 barrels ("bbl") per day for the period from September 1, 2009 to April 30, 2010. This contract consisted of a CAD$81.60 per bbl forward sale agreement. As at December 31, 2009, an unrealized losses of $99,894 relating to these two contracts was recorded in accumulated other comprehensive income.

LIQUIDITY AND CAPITAL RESOURCES

Cash Balance and Cash Flow

The Company had cash and cash equivalents of $2,733,000 as at December 31, 2009. In addition to the cash balance, the Company also had accounts receivable of $725,000, most of which related to December 2009 oil and gas sales and had been received subsequent to December 31, 2009.

During 2009, through equity financing, asset sale and debt restructuring, the Company eliminated the working capital deficit of $12,700,000 as at December 31, 2008 and ended 2009 with a positive working capital of $410,000.

During 2009, the Company successfully completed a turnaround on its oil & gas operation to reduce operating costs and improve operating netback. Together with the netback from two successful wells drilled in 2010 Q1, we expect the Company will generate positive operating cash flow beginning 2010 Q2, based on the current oil price of US$80 per barrel and gas price of US$4 per Mcf on NYMEX.

Bank Loan and Bridge Loan Financing

In August 2008, DEAL secured a revolving operating loan facility with a Canadian Bank for up to $7,000,000. In accordance with the terms of the facility, DEAL is required to maintain an adjusted working capital ratio of not less than 1.10:1. The adjusted working capital ratio is defined as the ratio of (i) current assets plus any undrawn availability under the facility, to (ii) current liabilities less any amount drawn under the facility.

As at December 31, 2009, DEAL was in compliance with the working capital ratio requirement. As at March 22, 2010, the bank line of credit was completely paid off.

Subsequent to December 31, 2009, DEAL acquired a credit facility for up to $5,000,000. The first 2,000,000 of the facility was used to refinance the DEAL's existing bank facility and fund its working capital. The remainder of the line is accessible subject to additional lender review. The facility carries interest rate at 12% per annum, subject to a 1% fee on any amount drawn and a 2% fee on repayment. DEAL also paid a $50,000 commitment fee. As at March 22, 2010, $1,500,000 was drawn under this facility. The proceeds of this bridge loan require lender's approval before it can be transferred to Dejour.

This bridge loan financing provides Dejour with an important, non-dilutive credit facility that allows for the seamless transition of its future requirements to a senior conventional lender, once the 2010 production enhancements at Woodrush have been successfully concluded.

Capital Resources

Subsequent to 2009, the Company raised $1 million from the issuance of flow-through shares for the drilling program in 2010 Q1. The Company does not have any drilling commitment in the remainder of 2010.

The Company plans to drill at least two wells in Canada during the remainder of 2010. The Company also plans to drill an exploratory well in an oil prospect at South Rangely in the US.

The Company plans to fund the drilling program through a combination of debt, equity or joint ventures.

Contractual Obligations

As of December 31, 2009, 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)	2010	2011	2012	2013	2014	Thereafter	Total
	$	$	$	$	$	$	$
Operating Lease Obligations	187	73	73	73	49	Nil	455
Bridge Loan	1,500	-	-	-	-	Nil	1,500
Other long-term Obligations	-	2,458	-	-	-	Nil	2,458
Total	1,687	2,531	73	73	49	Nil	4,413

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.

TRANSACTION WITH RELATED PARTIES

HEC loan to DEAL

During 2008, DEAL borrowed $1.95 million from HEC, a private company controlled by the CEO of the Company. The fund was used in oil & gas exploration activities. During 2009, $150,000 was repaid. As at June 22, 2009, the Company assumed from DEAL the HEC loan and the balance was Nil as at December 31, 2009.

HEC loan to the Company

During 2008, the Company borrowed $600,000 from HEC used for the purchase of the Montney ("Buick Creek") property in northeastern British Columbia. During 2009, this loan was repaid.

During, as consideration for HEC agreeing to postpone the HEC loan to DEAL and providing the additional loan of $600,000 to the Company, HEC was granted an option to become a working interest partner with DEAL. Upon electing to become a working interest partner, HEC must pay DEAL an amount equal to 10% of the actual price paid for the acquisition of the Buick Creek property. HEC is also required to pay its pro-rata share of the operating costs. During 2009, HEC exercised its option and elected to become a 10% working interest partner in DEAL's Buick Creek property. The option price was $90,642.

In 2009, the Company entered into an agreement with HEC in regard to the outstanding debt of $1,800,000 assumed from DEAL by the Company. Pursuant to the agreements, $450,000 of the debt was converted into 1,363,636 units consisting of 1,363,636 common shares and 681,818 common share purchase warrants exercisable at a price of

$0.55 for a period of 5 years. $1,350,000 of the debt was converted into a 12% note due on January 1, 2011 and the Company is required to pay 3% fee on the outstanding balance of the loan as at December 31, 2009. As a result of the sale of 5% working interest in the Drake/Woodrush area to HEC in December 2009, both parties were agreed to reduce the loan balance by the purchase price after taxes and adjustments of $911,722. In addition, the loan balance was further reduced by a payment of $50,351. As at December 31, 2009, $387,927 remained outstanding.

Brownstone loan to the Company

In 2008, Brownstone Ventures Inc. ("Brownstone"), a company which owns more than 10% of outstanding common shares of the Company and one of Brownstone's directors also serves on the board of directors of the Company, provided the Company with a $4,078,800 (US $4,000,000) secured loan, which was used to purchase the additional acreage interests in the Colorado/Utah Projects. During 2008, a repayment of $222,948 (US$220,000) was made and at December 31, 2008 a balance of $4,604,040 (US$3,780,000) was outstanding.

During 2009, the Company entered into agreements with Brownstone in regard to the outstanding debt of $4,604,040 (US$3,780,000). Pursuant to the agreements, US$2,000,000 of the debt was converted into 6,666,667 units consisting of 6,666,667 common shares and 3,333,333 common share purchase warrants exercisable at a price of $0.55 for a period of 5 years. The fair value of the units was estimated to be US$2,000,000. The remaining US$1,780,000 (C$2,070,140) of the debt was converted into a Canadian dollar denominated 12% note due on January 1, 2011.

CONTINGENCY

The Company was involved in a termination claim and litigation from a former officer and director arising in the normal course of business. Subsequent to December 31, 2009, both parties were agreed to settle the claim and the Company made a settlement payment of $100,000 to the former director and officer. It was included in accounts payable and accrued liabilities as at December 31, 2009.

SUBSEQUENT EVENTS

a) Stock Options

Subsequent to December 31, 2009, the Company granted a total of 3,053,000 incentive stock options with a weighted average exercise price at $0.35 per share to independent directors, management, officers, employees and consultants of the Company. The options can be exercised for periods ending up to February 15, 2015.

b) Bank Line of Credit and Bridge Loan Financing

Subsequent to December 31, 2009, the bank line of credit was completely paid off.

In February 2010, the Company acquired a credit facility for up to $5 million. The first $2 million of the facility was used to refinance the Company's existing bank facility and fund its working capital. The remainder of the line is accessible subject to additional lender review. The facility carries interest rate at 12% per annum, subject to a 1% fee on any amount drawn and a 2% fee on repayment. The Company also paid a $50,000 commitment fee. As at March 22, 2010, $1,500,000 was drawn under this facility.

c) Private Placement

In March 2010, the Company sold 2,907,334 flow-through units at $0.35 per unit. Each unit consists of one common share and one-half of one common share purchase warrant. Each whole warrant entitles the holder to acquire one additional common share of the Company. The Company issued 1,453,667 share purchase warrants, exercisable at $0.45 per warrant on or before March 3, 2011. Gross proceeds raised were $1,018,000. In connection with this private placement, the Company paid finders' fees of up to 6.25% of the proceeds in cash. The Company also issued 37,423 agents' warrants, exercisable at $0.45 per warrant on or before March 3, 2011.

RECENTLY ADOPTED ACCOUNTING POLICIES AND FUTURE ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Policies

(i) Effective January 1, 2009, the Company adopted the new recommendations of the CICA under CICA Handbook Section 3064 Goodwill and Intangible Assets, which replaces Section 3062, Goodwill and Other Intangible Assets, and Section 3450, Research and Development Costs. This new section establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill remain unchanged from the standards included in the previous Section 3062. The adoption of this new standard had no effect on the amounts disclosed in the financial statements.

(ii) Effective January 1, 2009, the Company adopted the newly issued guidance of the Emerging Issues Committee EIC-173, Credit Risk and the Fair value of Financial Assets and Liabilities, which requires that an entity should take into account the credit risk of the entity and the counterparty in determining the fair value of financial assets and financial liabilities. This guidance is adopted retrospectively, with restatement. No retroactive revision was disclosed related to the prior period as there were no effects on the fair values of financial assets and financial liabilities.

(iii) Effective January 1, 2009, the Company adopted the newly issued guidance of the Emerging Issues Committee EIC-174, Mining Exploration Costs, which provides guidance on the accounting and the impairment review of exploration costs. The adoption of this EIC did not have an effect on the Company's financial statements.

(iv) Effective January 1, 2009, the Company adopted the amended CICA Handbook Section 1000, Financial Statement Concepts, which clarifies the criteria for recognition of an asset, reinforcing the distinction between costs that should be expensed and those that should be capitalized. The adoption of this Section did not have an effect on the Company's financial statements.

Future Accounting Pronouncements

The CICA issued the following new Sections: 1582 Business Combinations, 1601 Consolidations, and 1602 Non-Controlling Interest. These standards are effective January 1, 2011. The impact of the adoption of these standards on the Company's financial statements has not yet been determined. The Company is currently evaluating the effects of adopting these standards.

International Financial Reporting Standards ("IFRS")

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRS") by the end of 2011. The transition date of January 1, 2011 will require the restatement for comparative purposes of amounts reported by the Company for the year ended December 31, 2010.

The Company is currently evaluating the impact of adopting IFRS on its consolidated financial statements. The Company is in the first phase of its transition program, which includes scoping to identify the significant accounting policy differences and their related areas of impact in terms of systems, procedures and financial statement presentation. The Company also is in the assessment phase of the design and work plan to calculate the differences between IFRS and Canadian GAAP, and the impact on its financial statements, disclosures and operations. The Company will address the design, planning, solution development and implementation of the conversion in 2010.

Expected Accounting Policy Impacts

The Company's significant areas of impact continue to include property, plant and equipment ("PP&E"), impairment testing. These areas of impact have the greatest potential impact to the Company's financial statements. The following discussion provides an overview of these areas, as well as the exemptions available under IFRS 1, *First-time Adoption of International Financial Reporting Standards*. In general, IFRS 1 requires first time adopters to retrospectively apply IFRS, although it does provide optional and mandatory exemptions to these requirements.

Property, Plant and Equipment

Under Canadian GAAP, the Company follows the CICA's 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 are depleted using the unit-of-production method based on proved reserves determined using estimated future prices and costs. Upon transition to IFRS, the Company will be required to adopt new accounting policies for upstream activities, including pre-exploration costs, exploration and evaluation costs and development costs.

Pre-exploration costs are those expenditures incurred prior to obtaining the legal right to explore and must be expensed under IFRS. Currently, the Company capitalizes and depletes pre-exploration costs within the country cost centre. In 2008 and 2009, these costs were not material to the Company.

Exploration and evaluation costs are those expenditures for an area or project for which technical feasibility and commercial viability have not yet been determined. Under IFRS, the Company will initially capitalize these costs as Exploration and Evaluation assets on the balance sheet. When the area or project is determined to be technically feasible and commercially viable, the costs will be transferred to PP&E. Unrecoverable exploration and evaluation costs associated with an area or project will be expensed.

Development costs include those expenditures for areas or projects where technical feasibility and commercial viability have been determined. Under IFRS, the Company will continue to capitalize these costs within PP&E on the balance sheet. However, the costs will be depleted on a unit-of-production basis over an area level (unit of account) instead of the country cost centre level currently utilized under Canadian GAAP. The Company has not finalized the areas or the inputs to be utilized in the unit-of-production depletion calculation.

Under IFRS, upstream divestures will generally result in a gain or loss recognized in net earnings. Under Canadian GAAP, proceeds of divestitures are normally deducted from the full cost pool without recognition of a gain or loss unless the deduction would result in a change to the depletion rate of 20 percent or greater, in which case a gain or loss is recorded.

The Company expects to adopt the IFRS 1 exemption, which allows the Company to deem its January 1, 2010 IFRS upstream asset costs to be equal to its Canadian GAAP historical upstream net book value. On January 1, 2010, the IFRS exploration and evaluation costs are expected to be equal to the Canadian GAAP unproved properties balance and the IFRS development costs are expected to be equal to the full cost pool balance. The Company will allocate this upstream full cost pool over reserves to establish the area level depletion units.

Impairment

Under Canadian GAAP, the Company is required to recognize an upstream impairment loss if the carrying amount exceeds the undiscounted cash flows from proved reserves for the country cost centre. If an impairment loss is to be recognized, it is then measured at the amount the carrying value exceeds the sum of the fair value of the proved and probable reserves and the costs of unproved properties.

Under IFRS, the Company is required to recognize and measure an upstream impairment loss if the carrying value exceeds the recoverable amount for a cash-generating unit. Under IFRS, the recoverable amount is the higher of fair value less cost to sell and value in use. Impairment losses, other than goodwill, are reversed under IFRS when there is an increase in the recoverable amount. The Company will group its upstream assets into cash-generating units based on the independence of cash inflows from other assets or other groups of assets.

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 December 31, 2009. 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 December 31, 2009 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 December 31, 2009, 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. 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.

There were no changes in the Company's internal control over financial reporting that occurred during the three months ended December 31, 2009 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. 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 MEASURE

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

Operating netback and operating cash flow are financial terms that are not considered measures under Canadian generally accepted accounting principles ("GAAP"). Operating netback is calculated as revenue less royalties and operating expenses. Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Both measures are widely used to assess an oil & gas company's ability to generate cash which is used to internally fund exploration and development activities and to service debt. Operating netback and operating cash flow should not be considered as an alternative to net income, cash flows from operating, investing or financing activities as an indicator of cash flows, or as a measure of liquidity. Dejour's method of calculating these measures may differ from other companies and, accordingly, they may not be comparable to measures used by other companies.

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
BOPD	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.
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.