DEJOUR ENTERPRISES LTD.
ENERGY. INDEPENDENCE.

MANAGEMENT DISCUSSION AND ANALYSIS

For the Three Months Ended March 31, 2010

Date of Report: May 11, 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 and the interim unaudited consolidated financial statements for the three months ended March 31, 2010.

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 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 129,000 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.

Q1 2010 HIGHLIGHTS

During the three months ended March 31, 2010, the Company continued its focus on the operational efficiency and asset and debt restructure while maintaining all prospective acreage holdings and positioning for renewed drilling activities as both the business environment and commodity prices improved.

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

1. In March, we successfully drilled, completed and tested two additional wells in the Woodrush area, providing the Company with the expectation of positive operating cash flow to be generated in the 2nd quarter of 2010. The first well was productive in the Gething formation and tested at a rate in excess of 900 MCFD (675 MCFD net to Dejour) of natural gas. The second well was productive in the Halfway formation and tested at a rate in excess of 500 BOPD (375 BOPD net to Dejour) of oil. These two wells will be tied into production in the 2nd quarter of 2010.

2. Obtained a credit facility of up to $5 million, allowing the Company to refinance its existing bank facility and funds its working capital.

3. Raised $1 million in equity under challenging market conditions, allowing the Company to execute its drilling program in the quarter.

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. (NYSE: WMB) and Bill Barrett Corporation (NYSE: BBG) are developing and producing on adjacent acreage to the east, west and north of the Company's acreage. An independent reserve evaluator, Gustavson Associates, assigned 90 BCF in proven undeveloped reserves to Dejour's net acreage at Gibson Gulch as of December 31, 2009.

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. During Q1 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

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 with Dejour currently holding a 72% working interest of 22,000 acres in North Rangely.

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 pay in the Williams Fork at Roan Creek will be somewhat thinner than is found to the east, Roan Creek has potential for pay in the Mancos/Niobrara interval that 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 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 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.

Prospective acreage is 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 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 three months ended March 31, 2010 are as follows:

	December 31, 2009	March 31, 2010		
	Net Book Value	**Net Expenditures**	**Write-off**	**Net Book Value**
US Oil and Gas Properties				
Colorado/Utah Projects				
Acquisition and lease rental	$ 28,115,687	$ 60,533	$ -	$ 28,176,220
Geological and geophysical	19,186	4,684	-	23,870
Capitalized general and administrative	313,577	81,076	-	394,653
	28,448,450	146,293	-	28,594,743
Others				
Acquisition	167,674	-	-	167,674
	167,674	-	-	167,674
Total US Oil and Gas Properties	**$ 28,616,124**	**$ 146,293**	**$ -**	**$ 28,762,417**

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 December 31, 2009, gas production was limited due to restrictions imposed by a third party providing compression services. December 2009 production averaged 277 BOE/D (122 BOPD of oil and 930 MCFD of gas). In March 2010, the Company installed gas compression facilities which increased gas production capacity 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 in the 2nd quarter of 2010.

As at March 31, 2010, 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 room for value increase. Based on the recommendations of that study, the Company implemented a five point program that 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 2009, 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. Proceeds 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 March 31, 2010.

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.

Saddle Hills

DEAL maintains a 25% working interest in 5,000 acres with two capped gas wells in the Saddle Hills area. The two wells are operated by Zargon Energy Trust, one of the Company's joint-venture partners. The recent announcement by the Alberta government on the lowering of oil and gas royalties will change the economics of the wells. We are waiting for details of the new royalty regime and will then discuss future development plan with Zargon.

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 three months ended March 31, 2010 is as follows:

	December 31, 2009	March 31, 2010		
	Net Book Value	Expenditures (Dispositions), Net	Write-off / Depletion	Net Book Value
Canadian Oil and Gas Properties				
Drake/Woodrush				
Land acquisition and retention	$ 386,110	$ 3,035	$ -	$ 389,145
Drilling and completion	5,283,495	1,104,430	-	6,387,925
Equipping and facilities	10,114,948	361,802	-	10,476,750
Geological and geophysical	454,956	614,495	-	1,069,451
Capitalized general and administrative	266,808	14,432	-	281,240
	16,506,317	2,098,194	-	18,604,511
Buick Creek (Montney)				
Land acquisition and retention	827,073	-	-	827,073
Capitalized interest	80,236	-	-	80,236
Capitalized general and administrative	8,473	7,770		16,243
	915,782	7,770	-	923,552
Saddle Hills				
Land acquisition and retention	4,948	-	-	4,948
Drilling and completion	887,902	478	-	888,380
Equipping and facilities	54,571	303	-	54,874
Geological and geophysical	78,407	-	-	78,407
Capitalized general and administrative	2,164	-		2,164
	1,027,992	781	-	1,028,773
Others				
Land acquisition and retention	1,623,177	1,971	-	1,625,148
Drilling and completion	4,420,145	3,198	-	4,423,343
Equipping and facilities	484,095	-	-	484,095
Geological and geophysical	952,530	-	-	952,530
Capitalized general and administrative	402,795	-	-	402,795
	7,882,742	5,169	-	7,887,911
Corporate Costs				
Assets retirement obligation	250,151	-	-	250,151
Depletion	(10,018,351)	-	(735,001)	(10,753,352)
Impairment	(3,955,854)	-	-	(3,955,854)
	(13,724,054)	-	(735,001)	(14,459,055)
Total Canadian Oil and Gas Properties	**$ 12,608,779**	**$ 2,111,914**	**$ (735,001)**	**$ 13,985,692**

The following table summarizes the breakdown of capital expenditures net of dispositions by type for the three months ended March 31, 2010 and 2009:

	Three Months Ended March 31 2010	Three Months Ended March 31 2009
Land acquisition and retention	$ 65,539	$ 140,973
Drilling and completion	1,108,106	155,944
Equipping and facilities	362,105	99,731
Geological and geophysical	619,179	16,132
Capitalized general and administrative	103,278	176,435
	$ 2,258,207	$ 589,215

Daily Production

	March 31, 2010	March 31, 2009
By Product		
Natural gas (mcf/d)	**1,073**	2,362
Natural gas liquids (bbls/d)	**7**	8
Oil (bbls/d)	**131**	360
Total (boe/d)	**317**	762

The production for the three months ended March 31, 2010 ("Q1 2010") averaged 317 BOE/D, a decrease of 58% compared to the three months ended March 31, 2009 ("Q1 2009"). The decrease in production was the result of disposition of 100% interest in the Carson Creek area and 25% interest in the Woodrush/Drake properties in 2009. In addition, one gas well was shut in during the installation of a new compressor in the first half of Q1 2010. By mid-March, substantially all of the curtailed production was brought back on line and production rate had increased to 465 BOE/D (120 BOPD and 2,100 MCFD). As the two new wells will be tied into production in the 2nd quarter of 2010, we expect the production rate will increase accordingly.

URANIUM EXPLORATION PROJECTS

As at March 31, 2010, the Company maintained a 10% carried interest and 1% Net Smelter Return on approximately 578,365 acres of uranium exploration claims and leases. During Q1 2010, there was no expiration of claims or leases. The carrying value of the Company's 10% carried interest and 1% Net Smelter Return was $533,085 as at March 31, 2010 and December 31, 2009.

SHARE CAPITAL

The following is a summary of share transactions for the three months ended March 31, 2010 and for the year ended December 31, 2009:

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, 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
- Share issuance costs related to prior share offerings	-		(146,005)
- For cash by private placement, net of share issuance costs	2,907,334		910,281
Balance at March 31, 2010	98,698,372	$	73,323,780

As at May 11, 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, 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
Options granted	3,053,000	0.35	
Options exercised	-	-	
Options cancelled and expired	(100,000)	0.45	
Balance, March 31, 2010	7,369,682	$ 0.41	3.88 years

Details of stock options vested and exercisable as at March 31, 2010 are as follows:

Number of Options Outstanding and vested	Exercise Price	Weighted Average Remaining Contractual Life (Years)
1,352,375	$ 0.45	2.84
120,000	$ 0.50	0.75
78,182	$ 0.55	0.75
419,125	$ 0.35	4.36
1,969,682	$ 0.44	2.95

As at March 31, 2010, 419,125 outstanding and vested options were “in the money” (the exercise price was less than the market trading price). If these options were fully exercised, the Company would realize approximately $147,000 in additional capital.

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, 2008	2,104,129	$ 3.35	0.40 years
Warrants issued	14,736,150	0.47	
Warrants expired	(2,104,129)	3.35	
Balance, December 31, 2009	14,736,150	0.47	4.36 years
Warrants issued	1,491,090	0.45	
Balance, March 31, 2010	16,227,240	$ 0.47	3.82 years

Details of warrants outstanding as at March 31, 2010 are as follows:

Number of Warrants Outstanding	Exercise Price	Weighted Average Remaining Contractual Life (Years)
2,000,000	$ 0.50	1.23
4,015,151	$ 0.55	4.23
8,075,000	US$0.40	4.73
645,999	US$0.46	4.60
1,491,090	$ 0.45	0.92
16,227,240		

RELATED PARTY TRANSACTIONS

During the three months ended March 31, 2010 and 2009, the Company entered into the following transactions with related parties:

a) The Company incurred a total of $108,123 (2009 - $108,337) in consulting and professional fees and a total of $Nil (2009 - $34,506) in rent expenses to the companies controlled by officers of the Company.

b) The Company incurred a total of $63,559 (2009 - $128,294) in interest expense and finance fee to related parties.

c) The Company received total rental income of $7,500 (2009 - $7,500) from companies controlled by officers of the Company.

d) The Company received total consulting fee income of $Nil (2009 - $57,100) from a related party which owns more than 10% of the Company's outstanding common shares.

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 – THREE MONTHS ENDED MARCH 31, 2010 AND 2009

Summary of Operational Highlights

DEAL Production and Netback Summary

	Three Months Ended March 31, 2010	2009
Production Volumes:		
Oil (bbls)	11,814	32,400
Gas (mcf)	96,608	212,600
Natural gas liquids (bbls)	621	726
Total (BOE)	28,536	68,559
Average Price Received:		
Oil ($/bbls)	71.60	42.04
Gas ($/mcf)	5.04	4.79
Natural gas liquids ($/bbls)	23.58	43.21
Total ($/BOE)	47.22	35.19
Royalties ($/BOE)	7.74	7.68
Operating Expenses – compressor installation ($/BOE)	7.71	-
Other Operating Expenses ($/BOE)	21.82	14.56
Total Operating Expenses ($/BOE)	29.53	14.56
Netbacks ($/BOE)	9.95	12.95

Revenues

		Three Months Ended March 31 2009		Three Months Ended March 31 2009
Revenue				
Natural gas	$	**486,983**	$	1,018,820
Oil		**845,841**		1,362,217
Natural gas liquids		**14,639**		31,389
Total oil and gas revenue		**1,347,463**		2,412,426
Realized financial instrument gain		**(42,407)**		289,561
Total revenue	$	**1,305,056**	$	2,701,987

For Q1 2010, the Company recorded $860,000 in crude oil and natural gas liquids sales and $487,000 in natural gas sales as compared to $1,394,000 in crude oil and natural gas liquids sales and $1,019,000 in natural gas sales for Q1 2009. The decrease was mainly the result of disposition of 100% interest in the Carson Creek area and 25% interest in the Woodrush/Drake properties in 2009. In addition, one gas well was shut in during the installation of a new compressor in the first half of Q1 2010. By mid-March, substantially all of the curtailed production was brought back on line and production rate had increased to 465 BOE/D (120 BOPD and 2,100 MCFD). As the two new wells will be tied into production in the 2nd quarter of 2010, we expect the production rate will increase accordingly.

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 March 31, 2010 and March 31, 2009:

	Three Months Ended March 31 2010	Three Months Ended March 31 2009
Dejour Average Prices		
Natural gas ($/mcf)	**$ 5.04**	$ 4.79
Oil ($/bbl)	**71.60**	42.04
Total average price ($/boe)	**$ 47.22**	$ 35.19
Benchmark Pricing		
Western Canadian Select (WCS) ($/bbl)	**$ 72.53**	$ 49.66
Natural gas - AECO-C Spot ($ per mcf)	**$ 5.36**	$ 4.92

Both the average natural gas sales prices and AECO-C daily spot prices for Q1 2010 were comparable to the prices received for Q1 2009. Oil prices received for Q1 2010 increased to $71.60 per barrel ("bbl"), compared to $42.04 per bbl for Q1 2009.

Royalties

	Three Months Ended March 31 2010	Three Months Ended March 31 2009
Royalties		
Crown	**$ 197,736**	$ 352,882
Freehold and GORR	**23,213**	173,474
Total royalties	**$ 220,949**	$ 526,356
$ per boe	**7.74**	7.68
As a percentage of oil and gas revenue	**16%**	22%

Royalties for Q1 2010 were $221,000 or $7.74 per BOE as compared to $526,000 or $7.68 per BOE for Q1 2009. The decrease in royalties was mainly due to the disposition of 100% interest in the Carson Creek area in 2009. Carson Creek is located in the province of Alberta and is subject to higher GORR and Crown royalty rates.

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 and rental, workovers, fuel and power. Operating and transportation expenses for Q1 2010 were $843,000 or $29.53 per BOE as compared to $998,000 or $14.56 per BOE for Q1 2009. On a per BOE basis, operating and transportation expenses are higher than the prior year's quarter for the following reasons:

- In January 2010, the Company incurred approximately net $220,000 for the installation of a rental compressor in the Woodrush field, resulting in higher per unit costs for the current quarter, when compared to the prior year's quarter.

- Delays in completing the installation of the compressor and other operational disruptions during the installation process resulted in the curtailed gas production in the first half of Q1 2010. As the majority of the operating expenses are fixed costs, therefore they are spread over a lower production base, resulting in higher per unit costs for Q1 2010.

Excluding the non-recurring installation cost of the compressor and the production delays and shut-in, the operating costs per BOE for Q1 2010 would have been comparable to the prior year's quarter. However, the installation of the compressor will benefit the Company by allowing us to increase gas production while at the same time reduce ongoing compression costs and operating costs.

Operating Netbacks

Operating netbacks for the current quarter were $9.95 per BOE as compared to $12.95 per BOE for Q1 2009. The netbacks were impaired by $7.71 per BOE being the costs associated with the installation of the compressor. Excluding these non-recurring costs, the resultant netbacks for Q1 2010 were actually $17.66 per BOE, a 36% improvement over the prior year's quarter of $12.95 per BOE.

General and Administrative Expenses

General and administrative expenses increased to $987,000 for Q1 2010 from $938,000 for Q1 2009. The increase was primarily due to the legal fees associated with the settlement of termination claim litigation from a former officer and director.

Interest and Finance Fees

For Q1 2010, the Company recorded interest and finance fees of $252,000, compared to $200,000 for Q1 2009. The increase was mainly due to the loan fees for setting up a credit facility of up to $5 million with Toscana Capital Corporation. The facility was obtained from Toscana in March 2010 to refinance the Company's existing bank facility and fund working capital.

Amortization, Depletion and Accretion

For Q1 2010, amortization and depletion of property and equipment and accretion of asset retirement obligations was $746,000 compared to $2,710,000 for Q1 2009. The decrease was due to the lower production level for the current quarter.

Stock Based Compensation

For Q1 2010, the Company recorded non-cash stock based compensation expense of $164,000 compared to $210,000 for Q1 2009. The decrease was because many of the stock options previously granted had been fully vested.

Income Taxes, Foreign Exchange Loss and Other Items

Future income tax recovery for Q1 2010 was $Nil, as compared to future income tax recovery of $779,000 for Q1 2009. As at March 31, 2010, the Company did not have recognized future income tax assets associated with the potential income tax benefits because their realization is uncertain. Therefore, no future income tax recovery is recorded for the current quarter. The balance of future income tax liability as at March 31, 2009, 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, was lower than the balance as at December 31, 2008, resulting in future income tax recovery for Q1 2009.

Foreign exchange loss was decreased by $136,000 to $16,000 for Q1 2010 from $152,000 for Q1 2009. At the end of 2008, the Company had a US dollar denominated loan of $3.8 million from a related party and recorded a foreign exchange loss in Q1 2009 due to the increase in the value of US dollars. In June 2009, the loan was converted into a Canadian dollar denominated loan and no foreign currency revaluation was necessary in Q1 2010.

The decrease in interest and other income was because no management fee income was received from a related party in Q1 2010. In Q1 2009, management fee income was received for financial advisory and project management services provided to the related party.

Net Loss

The Company's net loss for Q1 2010 was $1,915,000 or $0.02 per share, compared to a net loss of $2,449,000, or $0.03 per share for Q1 2009. In Q1 2009, the Company had a loss on disposition of its investment in common shares of Titan Uranium Inc. of $311,000 and a non-cash equity loss from Titan of $142,000. The equity loss from Titan relates to the Company's proportionate share of Titan's loss in the current period.

SUMMARY OF QUARTERLY RESULTS

The following summary for the eight most recently completed financial quarters ending March 31, 2010 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.

	1st Quarter ended March 31, 2010 $	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 $
Revenues	1,305,056	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	(1,914,974)	(7,048,949)	(2,528,039)	(780,872)	(2,449,058)	(15,151,051)	(3,038,792)	(1,143,679)
Basic and diluted net loss per common share	(0.02)	(0.08)	(0.03)	(0.01)	(0.03)	(0.21)	(0.04)	(0.02)

The substantial 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 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 line of credit, accounts payable, and loans from related parties. 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. In March 2010, the Company unwound both the natural gas hedge and the crude oil hedge, resulting in a total realized loss of $42,000. There were no derivative contracts outstanding as at March 31, 2010.

LIQUIDITY AND CAPITAL RESOURCES

Cash Balance and Cash Flow

The Company had cash and cash equivalents of $1,336,000 as at March 31, 2010. In addition to the cash balance, the Company also had accounts receivable of $882,000, most of which related to March 2010 oil and gas sales and had been received subsequent to March 31, 2010.

Our investing activities during Q1 2010 were financed primarily by the $1 million raised from the issuance of flow-through shares and draw down of bridge loan during the quarter.

In 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 the current quarter, we expect to generate positive operating cash flow commencing the 2nd quarter of 2010, 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. On March 22, 2010, the bank line of credit was completely paid off.

On March 22, 2010, DEAL acquired a credit facility for a bridge loan of 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 of engineering reports on oil and gas reserves being developed or acquired. 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 31, 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. The bridge loan is due on September 22, 2010. Subject to the agreement of the lender, the loan can be extended for a period of maximum 3 months. In addition, the extension will be subject to a 1% extension fee per month on the outstanding loan balance at the beginning of each month.

Working Capital Position

As at March 31, 2010, the Company had a working capital deficit of to $4,337,000. The working capital deficit mainly consisted of loans from related parties and bridge loan drawn during Q1 2010. The Company plans to remedy the deficiency through the following:

- Once a new engineering evaluation is completed in the summer of 2010, the Company intends to obtain a credit facility with a conventional bank to refinance the existing bridge loan;

- The Company expects to generate positive operating cash flow commencing Q2 2010 from its oil and gas production in the Woodrush/Drake property. The Company brought two new wells into production in early May. One new oil well had been producing at an average rate of 750 BOPD (563 BOPD net to the Company). The Company believes this new oil well is a new oil pool and can be exempt from BC Crown royalty for the first 72,000 barrels of oil production. At the current production rate and oil price, this oil well alone is expected to generate an operating netback of $400,000 to $600,000 per month net to Dejour;

- If necessary and at the right market conditions, the Company may fund its working capital through additional debt or disposal of non-core asset or a combination of both.

Capital Resources

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 March 31, 2010, 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	118	73	73	73	49	Nil	386
Bridge Loan	1,500	-	-	-	-	Nil	1,500
Other Obligations	2,458	-	-	-	-	Nil	2,458
Total	4,076	73	73	73	49	Nil	4,344

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 the Company

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 March 31, 2010 and 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 a balance of $4,604,040 (US$3,780,000) was outstanding as at December 31, 2008.

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.

LITIGATION

The Company was involved in a termination claim and litigation from a former officer and director. In February 2010, both parties agreed to settle the claim and the Company made a settlement payment of $100,000 to the former director and officer.

SUBSEQUENT EVENTS

a) Production

On May 6, 2010, the Company installed flow lines and connected the new wells to the Woodrush production facility. The Halfway Oil well has been producing at an average rate of 750 BOPD since the commencement of production on May 6, 2010. On May 10, 2010, the Gething gas well commenced production at a rate of 1,120 MCFD.

b) Derivative Financial Instruments

The Company uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and provide the Company with downside protection insurance on the decrease of commodity prices.

As at May 7, 2010, the Company had the following put options, allowing the Company the right, but not the obligation, to sell Western Texas Instrument ("WTI") crude oil:

Crude oil Contract	Contract Month	Volume	Price per barrel
WTI Crude oil put options	August 2010	10,000 barrels per month	US$75
WTI Crude oil put options	September 2010	10,000 barrels per month	US$75

RECENTLY ADOPTED ACCOUNTING POLICIES AND FUTURE ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Policies

On January 1, 2010, the Company adopted the following Canadian Institute of Chartered Accountants ("CICA") Handbook sections:

- Business Combinations, Section 1582, which replaces the previous business combinations standard. The standard requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination and included in the statement of earnings. The adoption of this standard will impact the accounting treatment of future business combinations entered into after January 1, 2010.

- Consolidated Financial Statements, Section 1601, which, together with Section 1602 below, replace the former consolidated financial statements standard. Section 1601 establishes the requirements for the preparation of consolidated financial statements. The adoption of this standard had no material impact on the Company's consolidated financial statements.

- "Non-controlling Interests", Section 1602, which establishes the accounting for a non-controlling interest in a subsidiary in consolidated financial statements subsequent to a business combination. The standard requires a non-controlling interest in a subsidiary to be classified as a separate component of equity. In addition, net earnings and components of other comprehensive income are attributed to both the parent and non-controlling interest. The adoption of this standard has had no material impact on the Company's consolidated financial statements.

Future Accounting Pronouncements

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 March 31, 2010. 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 March 31, 2010 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 March 31, 2010, 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 March 31, 2010 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 cash flow, operating profits and operating netbacks are financial terms that are not considered measures under Canadian generally accepted accounting principles ("GAAP"). Operating cash flow represents net cash provided by operating activities before changes in assets and liabilities. Operating profits adjusts net income by non-operating items that Management believes reduces the comparability of the Company's underlying financial performance between periods. Operating netback is calculated as revenue less royalties and operating expenses. These 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. These measures 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.
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.