DEJOUR ENERGY INC.

RESOURCEFUL. ENTERPRISING.

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the Year Ended December 31, 2012

Date of Report: March 28, 2013

INTRODUCTION

The Company was incorporated under the law of Ontario, Canada, on March 29, 1968 under the name "Dejour Mines Limited". By articles of amendment dated October 30, 2001, the issued common shares were consolidated on the basis of one (1) new share for every fifteen (15) old shares and the name of the company was changed to Dejour Enterprises Ltd. On June 6, 2003, the shareholders approved a resolution to complete a one new share for three old share consolidation, which became effective on October 1, 2003. In 2005, the Company was continued into the province of British Columbia under the *Business Corporations Act* (British Columbia). On March 9, 2011, the Company changed its name from Dejour Enterprises Ltd. to Dejour Energy Inc.

The head office of Dejour is located at 598 – 999 Canada Place, Vancouver, British Columbia, V6C 3E1, and its registered and records office is located at 25th Floor, 700 West Georgia Street, Vancouver, British Columbia, V7Y 1B3. The common shares of Dejour are listed for trading on the Toronto Stock Exchange ("**TSX**"), on the New York Stock Exchange ("**NYSE**") under the symbol "DEJ", and on the Frankfurt Exchange under the symbol "D5R". The Company ceased to trade on the TSX Venture Exchange ("**TSX-V**") and graduated to the TSX effective November 20, 2008.

The following management's discussion and analysis ("MD&A") is dated March 25, 2013 and should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the years ended December 31, 2012 and 2011.

Additional information relating to Dejour can be found on SEDAR at www.sedar.com.

FORWARD-LOOKING STATEMENTS

This document contains expectations, beliefs, plans, goals, objectives, assumptions, information, and statements about future events, conditions, results of operations or performance that constitute "forward-looking information" or "forward-looking statements" (collectively, "forward-looking statements") under applicable securities laws. Undue reliance should not be placed on forward-looking statements. Forward-looking statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements. We caution that the foregoing list of risks and uncertainties is not exhaustive. Events or circumstances could cause actual dates to differ materially from those estimated or projected and expressed in, or implied by, these forward-looking statements. The forward-looking statements contained in this document are made as of the date hereof and the Company does not intend, and does not assume any obligation, to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise unless expressly required by applicable securities laws.

The information set out herein with respect to forecasted 2013 results is "financial outlook" within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding Dejour's reasonable expectations as to the anticipated results of its proposed business activities for 2013. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

NON-GAAP AND IFRS MEASURES

This document contains certain financial measures, as described below, which do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") or International Reporting Standards ("IFRS"). As these measures are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used. "Operating netback" is calculated by deducting royalties and operating and transportation expenses from gross oil and gas revenues. Operating netback is used by Dejour as key measures of performance and is not intended to represent operating profits nor should they be viewed as an alternative to income or loss or other measures of financial performance calculated in accordance with GAAP and IFRS.

OTHER MEASUREMENTS

All dollar amounts are referenced in Canadian dollars, except when noted otherwise. Some numbers in this MD&A have been rounded to the nearest thousand for discussion purposes. Where amounts are expressed on a barrel of oil equivalent ("BOE") basis, natural gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel. The term BOE may be misleading, particularly if used in isolation. A BOE conversion ratio six thousand cubic feet per barrel is based on an energy equivalency conversion method primarily applicable at a burner tip and does not represent a value equivalency at the wellhead. Natural gas liquids ("NGL's") in this discussion include condensate, propane, butane, and ethane.

CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

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

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

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

Decommissioning liability

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

Exploration and evaluation expenditure

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

Income taxes

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

Share-based payment transactions

The Company measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date at which they are granted. Estimating fair value for share-based payment transactions requires determining the most appropriate valuation model, which is dependent on the terms and conditions of the grant. This estimate also requires determining the most appropriate inputs to the valuation model including the expected life of the share option, volatility and dividend yield.

Impairment

A CGU is defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The allocation of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, similar exposure to market risks, shared infrastructures, and the way in which management monitors the operations. The recoverable amounts of CGUs and individual assets have been determined based on the higher of fair value less costs to sell or value-in-use calculations. The key assumptions the Company uses in estimating future cash flows for recoverable amounts are anticipated future commodity prices, expected production volumes and future operating and development costs. Changes to these assumptions will affect the recoverable amounts of CGUs and individual assets and may then require a material adjustment to their related carrying value. At December 31, 2012, the Company has two CGUs in Canada (Drake/Woodrush and Saddle Hills) and two CGUs in the United States (Kokopelli and South Rangely).

Financial instrument

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

Reserves

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

FUTURE ACCOUNTING CHANGES

Certain pronouncements were issued by the International Accounting Standards Board ("IASB") or the International Financial Reporting Interpretations Committee ("IFRIC") that are mandatory for accounting periods beginning after January 1, 2013 or later periods.

The following new standards, amendments and interpretations, have not been early adopted in these consolidated annual financial statements. The Company is currently assessing the impact, if any, of this new guidance on the Company's future results and financial position:

- IFRS 7 Financial Instruments: Disclosures, which requires disclosure of both gross and net information about financial instruments eligible for offset in the balance sheet and financial instruments subject to master netting arrangements. Concurrent with the amendments to IFRS 7, the IASB also amended IAS 32, Financial Instruments: Presentation to clarify the existing requirements for offsetting financial instruments in the balance sheet. The amendments to IAS 32 are effective as of January 1, 2014.

- IFRS 9 Financial Instruments is part of the IASB's wider project to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 retains but simplifies the mixed measurement model and establishes two primary measurement categories for financial assets: amortized cost and fair value. The basis of classification depends on the entity's business model and the contractual cash flow characteristics of the financial asset. The standard is effective for annual periods beginning on or after January 1, 2015.

- IFRS 10 Consolidated Financial Statements is the result of the IASB’s project to replace Standing Interpretations Committee 12, Consolidation – Special Purpose Entities and the consolidation requirements of IAS 27, Consolidated and Separate Financial Statements. The new standard eliminates the current risk and rewards approach and establishes control as the single basis for determining the consolidation of an entity. The standard is effective for annual periods beginning on or after January 1, 2013.

- IFRS 11 Joint Arrangements is the result of the IASB’s project to replace IAS 31, Interests in Joint Ventures. The new standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to be equity accounted. Under IAS 31, joint ventures could be proportionately consolidated. The standard is effective for annual periods beginning on or after January 1, 2013.

- IFRS 12 Disclosure of Interests in Other Entities outlines the required disclosures for interests in subsidiaries and joint arrangements. The new disclosures require information that will assist financial statement users to evaluate the nature, risks and financial effects associated with an entity’s interests in subsidiaries and joint arrangements. The standard is effective for annual periods beginning on or after January 1, 2013.

- IFRS 13 Fair Value Measurement defines fair value, requires disclosures about fair value measurements and provides a framework for measuring fair value when it is required or permitted within the IFRS standards. The standard is effective for annual periods beginning on or after January 1, 2013.

- IFRIC 20 Stripping costs in the production phase of a mine, IFRIC 20 clarifies the requirements for accounting for the costs of the stripping activity in the production phase when two benefits accrue: (i) unusable ore that can be used to produce inventory and (ii) improved access to further quantities of material that will be mined in future periods. IFRIC 20 is effective for annual periods beginning on or after January 1, 2013 with earlier application permitted and includes guidance on transition for pre-existing stripping assets.

- IAS 1, Presentation of Financial Statements was amended in June 2011. This standard requires companies preparing financial statements under IFRS to group items within Other Comprehensive Income (OCI) that may be reclassified to the profit or loss. The amendments also reaffirm existing requirements that items in OCI and profit of loss should be presented as either a single statement or two consecutive statements. The amendments to IAS 1 are effective as of January 1, 2013.

- IAS 28 Investments in Associates and Joint Ventures, prescribes the accounting for investments in associates and sets out the requirements for the application of the equity method when accounting for investments in associates and joint ventures. IAS 28 applies to all entities that are investors with joint control of, or significant influence over, an investee (associate or joint venture). The standard is effective for annual periods beginning on or after January 1, 2013.

DISCLOSURE CONTROLS OVER FINANCIAL REPORTING

The Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 of the Canadian Securities Administrators, to provide reasonable assurance that: (i) material information relating to the Company is made known to the CEO and the CFO by others, particularly during the period in which the interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

The CEO and the CFO have evaluated the effectiveness of Dejour's disclosure controls and procedures as at December 31, 2012 and have concluded that such disclosures and procedures are effective.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in National Instrument 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The Company is required to disclose any change in the Company's internal controls over financial reporting that occurred from October 1, 2012 to December 31, 2012 that has material affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes were identified during the period.

The CEO and CFO have evaluated the effectiveness of Dejour's internal controls over financial reporting as at December 31, 2012 and have concluded that such internal controls over financial reporting are effective.

Due to its inherent limitations, internal controls over financial reporting may not prevent or detect misstatements. In addition, projections or any evaluation relating to the effectiveness of future periods are subject to the risk that controls may become inadequate as a result of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

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.

GROWTH STRATEGY

The Company implements a full cycle exploration and development program and, at the same time, opportunistically seeks to acquire assets with exploitation potential. To complement this strategy, the Company has retained a team of experienced and qualified personnel to act quickly on new opportunities.

RESULTS OF OPERATIONS

FINANCIAL AND OPERATING HIGHLIGHTS

1. Executed a US$6.5 million financial contract with a private U.S. based oil and gas drilling fund whereby the parties agreed to form a partnership to complete the initial well in the Kokopelli Field and drill (and complete as required) three additional wells in early 2013. Total program cost will be approximately US$8.2 million;

2. Executed a sale and farm-out agreement covering about 7,450 acres of 100% owned western Piceance Basin lands to a listed U.S. oil and natural gas exploration and production company, for certain cash consideration and a commitment to carry the Company through the drilling and completion of three earning wells, with certain performance provisions. The Company will retain a 20% working interest in over 5,100 acres in this project;

3. Successfully tied in production at South Rangely from a discovery well drilled in 2011;

4. Successfully raised gross proceeds of US$4.7 million in equity, allowing the Company to support exploration, development and acquisition activities of its oil and gas properties and provide for additional working capital;

5. Added about 31,000 net acres to the Company's current landholdings in northwestern Colorado through a restructuring of its exploration joint venture with Brownstone Energy Inc., a joint venture partner;

6. Successfully completed construction of the first drilling pad and drilled the initial well in the Kokopelli area of the Piceance Basin;

7. Formation of a federal unit containing the leases adjacent to the lease on which the discovery well at South Rangely leasehold was drilled in 2011 in the Company's Piceance Basin area of operations; and

8. Successfully completed and tied into production the 3rd oil well at the Company's Woodrush property, north of Fort St. John, British Columbia.

DAILY PRODUCTION

	Three months ended December 31,		Year ended December 31,	
	2012	2011	2012	2011
By Product				
Oil and natural gas liquids (bbls/d)	193	242	198	223
Natural gas (mcf/d)	755	1,376	1,040	1,184
Total (boe/d)	319	471	372	421

The decrease in oil production for the current year was mainly the result of the temporary curtailment of production due to the pump installation and maintenance required to handle higher future oil production associated with the main producing oil well at Drake/Woodrush.

The substantial decrease in natural gas production for the current quarter was primarily the result of the reduction of natural gas production at Drake/Woodrush as the waterflood encroached upon the Halfway reservoir combined with normal production declines. Additionally, one of the producing gas wells at Drake/Woodrush was shut-in due to a workover during Q4 2012; this also contributed to the decline in gas production for the quarter.

SELECTED CONSOLIDATED FINANCIAL RESULTS

The following are selected financial results for the years ended December 31, 2012 and December 31, 2011:

	Three months ended December 31,		Year ended December 31,	
	2012	2011	2012	2011
	$	$	$	$
Gross Revenues	1,630,000	2,478,000	6,882,000	8,824,000
Operating Cash Flow (1)	(505,000)	(251,000)	(2,218,000)	(322,000)
Operating Loss (1)	(1,597,000)	(1,174,000)	(5,685,000)	(3,215,000)
EBITDA (1)	(572,000)	(2,339,000)	(489,000)	(1,710,000)
Adjusted EBITDA (1)	(133,000)	(182,000)	(1,464,000)	532,000
Loss for the period	(9,453,000)	(8,430,000)	(11,753,000)	(11,043,000)
Loss per common share	(0.063)	(0.069)	(0.083)	(0.092)

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

NON-GAAP MEASURES

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

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

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

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

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

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

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Operating Cash Flow

	Three months ended December 31, 2012	Three months ended December 31, 2011	Year ended December 31, 2012	Year ended December 31, 2011
	$	$	$	$
Cash flows from (used in) operating activities - GAAP	(959,000)	294,000	(3,227,000)	120,000
Add: changes in non-cash operating working capital	454,000	(545,000)	1,009,000	(442,000)
Operating Cash Flow - Non-GAAP	(505,000)	(251,000)	(2,218,000)	(322,000)

Operating Netback

	Three months ended December 31, 2012	Three months ended December 31, 2011	Year ended December 31, 2012	Year ended December 31, 2011
	$	$	$	$
Gross Revenues	1,630,000	2,478,000	6,882,000	8,824,000
Less: Royalties	(261,000)	(429,000)	(1,116,000)	(1,628,000)
Less: Operating and transportation	(792,000)	(857,000)	(3,793,000)	(2,499,000)
Operating Netback - Non-GAAP	577,000	1,192,000	1,973,000	4,697,000

Operating Loss

	Three months ended December 31, 2012	Three months ended December 31, 2011	Year ended December 31, 2012	Year ended December 31, 2011
	$	$	$	$
Loss for the period	(9,453,000)	(8,430,000)	(11,753,000)	(11,043,000)
Add back (losses) and deduct gains:				
Impairment losses	7,891,000	5,212,000	7,910,000	6,248,000
Change in fair value of warrant liability	(35,000)	2,044,000	(1,842,000)	1,580,000
Operating Loss - Non-GAAP	(1,597,000)	(1,174,000)	(5,685,000)	(3,215,000)

EBITDA

	Three months ended December 31, 2012	Three months ended December 31, 2011	Year ended December 31, 2012	Year ended December 31, 2011
	$	$	$	$
Loss for the period	(9,453,000)	(8,430,000)	(11,753,000)	(11,043,000)
Deferred tax recovery	-	-	-	(187,000)
Finance costs	188,000	72,000	588,000	868,000
Amortization, depletion and impairment losses	8,693,000	6,019,000	10,676,000	8,652,000
EBITDA - Non-GAAP	(572,000)	(2,339,000)	(489,000)	(1,710,000)

Adjusted EBITDA

	Three months ended December 31, 2012	Three months ended December 31, 2011	Year ended December 31, 2012	Year ended December 31, 2011
	$	$	$	$
EBITDA	(572,000)	(2,339,000)	(489,000)	(1,710,000)
Adjustments:				
Stock-based compensation	474,000	113,000	867,000	662,000
Change in fair value of warrant liability	(35,000)	2,044,000	(1,842,000)	1,580,000
Adjusted EBITDA - Non-GAAP	(133,000)	(182,000)	(1,464,000)	532,000

RESULTS OF OPERATIONS – YEAR ENDED DECEMBER 31, 2012 AND 2011

Summary of Operational Highlights

Production and Netback Summary	Year ended December 31, 2012	2011
Production Volumes:		
Oil and natural gas liquids (bbls)	72,567	81,468
Natural gas (mcf)	380,780	432,199
Total (BOE)	136,031	153,501
Average Price Received:		
Oil and natural gas liquids ($/bbls)	81.37	88.98
Natural gas ($/mcf)	2.57	3.64
Total ($/BOE)	50.59	57.49
Royalties ($/BOE)	8.20	10.61
Operating and Transportation Expenses ($/BOE)	27.66	16.18
Netbacks ($/BOE)*	14.73	30.70

*See Non-GAAP Measures

Revenues

	Year ended December 31, 2012	2011
	$	$
Gross Revenues	6,882,000	8,824,000
Royalties	(1,116,000)	(1,628,000)
Revenues, net of royalties	5,766,000	7,196,000
Financial instrument loss	(55,000)	(59,000)
Other income	33,000	34,000
Total revenue	5,744,000	7,171,000

For the year ended December 31, 2012 (“fiscal 2012”), the Company recorded $6,882,000 in oil and natural gas sales as compared to $8,824,000 in oil and natural gas sales for the year ended December 31, 2011 (“fiscal 2011”). The decrease in gross revenues was due to lower realized oil and gas prices and lower oil and gas production.

Royalties for fiscal 2012 decreased to $1,116,000 from $1,628,000 for fiscal 2011, due to lower oil and gas production. Royalties are mainly driven by the varying production mix between oil and gas.

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, 2012 and 2011:

	Year ended December 31, 2012	2011
	$	$
Dejour Realized Average Prices		
Oil and natural gas liquids ($/bbl)	81.37	93.00
Natural gas ($/mcf)	2.57	3.23
Total average price ($/boe)	50.59	57.15
Average Benchmark Prices		
Edmonton Par ($/bbl)	86.53	97.87
Natural gas - AECO-C Spot ($ per mcf)	2.40	3.47

For fiscal 2012, Dejour's average realized natural gas prices reflected lower benchmark prices compared to fiscal 2011. Oil prices received for fiscal 2012 decreased to $81.37 per barrel ("bbl"), compared to $93.00 per bbl for fiscal 2011. The decrease was due to the general downturn of the global economy, leading to lower commodity prices. In addition, the oil differential between West Texas Intermediate (WTI) oil to British Columbia light crude oil increased due to pipeline constraints, resulting in lower realized prices for the Company's oil.

Operating and Transportation Expenses

Operating and transportation expenses include all costs associated with the production of oil and natural gas and the transportation of oil and natural gas to the processing plants. The major components of operating expenses include labour, equipment maintenance, workovers, fuel and power. Operating and transportation expenses for fiscal 2012 increased to $3,793,000 from $2,499,000 for fiscal 2011. The increase was due to the expenditures associated with a major workover on one of the oil producing wells ($564,000), increased repairs and maintenance of oil wells, and higher waterflood implementation expenses.

Finance Costs and Change in Fair Value of Warrant Liability

Finance costs for fiscal 2012 decreased to $588,000 from $868,000 for fiscal 2011. The decrease was mainly attributable to the line of credit facility obtained in September 2011 that bears a lower interest rate, compared to the bridge loan with a relatively higher interest rate. Included in the finance costs for fiscal 2012 was $129,000 of the expenses related to the US$ denominated warrants issued as part of the US $4.7 million equity offering closed in June 2012.

For fiscal 2012, the non-cash change in fair value of warrant liability was a gain of $1,842,000, compared to a loss of $1,580,000 was recorded for fiscal 2011, primarily due to the decrease of the Company's share prices. The warrant liability relates to the fair value of certain warrants that were issued in the previous equity financings. These warrants are denominated in US dollars, which is different than the functional currency of the Company. Under IFRS, they are classified as liabilities and any change in the fair value is recognized in the profit or loss. Changes in fair value result from volatility in the Company's share prices and fluctuations in the US/Canadian dollar exchange rates. Lower shares prices of the

Company since the 2nd quarter of 2012 resulted in a lower valuation for these warrants and a higher non-cash valuation gain for the current year.

General and Administrative Expenses

General and administrative expenses for fiscal 2012 decreased to $3,433,000 from $4,042,000 for fiscal 2011. The Board and management's decision to not pay a bonus to employees for the year ended December 31, 2012 and the inclusion of such a bonus in 2011 accounted for much of the difference. Further, 2011 included non-recurring professional fees associated with the required conversion to the International Financial Reporting Standards (IFRS).

Stock Based Compensation

Non-cash stock based compensation expenses for fiscal 2012 were $867,000, compared to $662,000 for fiscal 2011. The increase in stock based compensation expense was primarily due to the issuance of a significant number of fully vested stock options in December 2012. In addition, re-price of some of the previously granted options in December 2012 also contributed to the increase in expense.

Amortization, Depletion and Impairment Losses

For fiscal 2012, amortization, depletion and impairment losses were $10,676,000, compared to $8,652,000 for fiscal 2011. Amortization and depletion of property and equipment for fiscal 2012 was $2,766,000, compared to $2,404,000 for fiscal 2011. The increase in amortization and depletion expenses was due to a lower reserve determination by the independent engineers of the Company's Canadian properties at Drake/Woodrush. Impairment losses of $7,910,000 for fiscal 2012, compared to $6,248,000 for fiscal 2011, because the carrying value of certain exploration and evaluation assets and property and equipment exceeded their recoverable amounts and certain leases for exploration and evaluation assets and property and equipment were expired.

Loss and Operating Loss

The Company's loss for fiscal 2012 was $11,753,000 or $0.083 per share, compared to a loss of $11,043,000 or $0.092 per share for fiscal 2011. The loss differential was primarily due to lower revenues and the increase in operating and transportation expenses and amortization, depletion and impairment losses.

The Company's operating loss for fiscal 2012 was $5,685,000, compared to $3,215,000 for fiscal 2011. The increase was mainly due to lower revenues and the increase in operating and transportation expenses. This was partly offset by the reduction in general and administrative expenses.

RESULTS OF OPERATIONS – THREE MONTHS ENDED DECEMBER 31, 2012 AND 2011

Summary of Operational Highlights

Production and Netback Summary	Three months ended December 31, 2012	2011
Production Volumes:		
Oil and natural gas liquids (bbls)	17,767	22,241
Natural gas (mcf)	69,479	126,633
Total (BOE)	29,347	43,346
Average Price Received:		
Oil and natural gas liquids ($/bbls)	78.33	93.00
Natural gas ($/mcf)	3.44	3.23
Total ($/BOE)	55.55	57.15
Royalties ($/BOE)	8.88	9.90
Operating and Transportation Expenses ($/BOE)	25.95	19.78
Netbacks ($/BOE)*	20.72	27.48

*See Non-GAAP Measures

Revenues

	Three months ended December 31, 2012	2011
	$	$
Gross Revenues	1,630,000	2,478,000
Royalties	(261,000)	(429,000)
Revenues, net of royalties	1,369,000	2,049,000
Financial instrument loss	-	-
Other income	8,000	8,000
Total revenue	1,377,000	2,057,000

For the three months ended December 31, 2012 (“Q4 2012”), the Company recorded $1,630,000 in oil and natural gas sales as compared to $2,478,000 in oil and natural gas sales for the three months ended December 31, 2011 (“Q4 2011”). The decrease in gross revenues was due to lower realized oil prices and lower oil and gas production in the current quarter. The lower production was due to a major workover and related shut-in of a key producing well at Drake/Woodrush.

Royalties for Q4 2012 decreased to $261,000 from $429,000 for Q4 2011, due to lower oil and gas production. Royalties are mainly driven by the varying production mix between oil and gas and market prices.

The following table summarizes the commodity prices realized by the Company and the crude oil and natural gas benchmark prices for the three months ended December 31, 2012 and 2011:

	Three months ended December 31,	
	2012	2011
	$	$
Dejour Realized Average Prices		
Oil and natural gas liquids ($/bbl)	78.33	88.98
Natural gas ($/mcf)	3.44	3.64
Total average price ($/boe)	55.55	57.49
Average Benchmark Prices		
Edmonton Par ($/bbl)	84.28	95.16
Natural gas - AECO-C Spot ($ per mcf)	3.60	3.67

For the current quarter, Dejour's average realized natural gas prices reflected lower benchmark prices compared to Q4 2011. Oil prices received for Q4 2012 decreased to $78.33 per barrel ("bbl"), compared to $88.98 per bbl for Q4 2011. The decrease was due to the general downturn of the global economy, leading to lower commodity prices. In addition, the oil differential between West Texas Intermediate (WTI) oil to British Columbia light crude oil increased due to pipeline constraints, resulting in lower realized prices for the Company's oil.

Operating and Transportation Expenses

Operating and transportation expenses include all costs associated with the production of oil and natural gas and the transportation of oil and natural gas to the processing plants. The major components of operating expenses include labour, equipment maintenance, workovers, fuel and power. Operating and transportation expenses for Q4 2012 decreased to $792,000 from $857,000 for Q4 2011. The decrease was due to lower oil and gas production.

Finance Costs and Change in Fair Value of Warrant Liability

Finance costs for the current quarter increased to $188,000 from $72,000 for the same quarter in prior year. The increase was primarily attributable to the finance fees associated with the termination of a debt financing commitment.

For the current quarter, the non-cash change in fair value of warrant liability was a gain of $35,000, compared to a loss of $2,044,000 was recorded for the same quarter in prior year. The warrant liability relates to the fair value of certain warrants that were issued in the previous equity financings. These warrants are denominated in US dollars, which is different than the functional currency of the Company. Under IFRS, they are classified as liabilities and any change in the fair value is recognized in the profit or loss. Changes in fair value result from volatility in the Company's share prices and fluctuations in the US/Canadian dollar exchange rates. Minor reduction of the Company's share prices in the current quarter resulted in a slightly lower valuation for these warrants and a trivial non-cash valuation gain for the current quarter.

General and Administrative Expenses

General and administrative expenses for the current quarter decreased to $937,000 from $1,374,000 for 2011 Q4. The Board and management's decision to not pay a bonus to employees for the year ended December 31, 2012 and the inclusion of such a bonus in 2011 accounted for much of the difference.

Stock Based Compensation

For the current quarter, the Company recorded non-cash stock based compensation expenses of $474,000, compared to $113,000 for Q4 2011. The substantial increase in stock based compensation expense was mainly due to the issuance of a significant number of fully vested stock options in the current quarter. In addition, re-price of some of the previously granted options in the current quarter also contributed to the increase in expense.

Amortization, Depletion and Impairment Losses

For the current quarter, amortization, depletion and impairment losses were $8,693,000, compared to $6,019,000 for Q4 2011. Amortization and depletion of property and equipment for Q4 2012 was $801,000, compared to $807,000 for Q4 2011. Impairment losses of $7,891,000 for Q4 2012, compared to $5,212,000 for Q4 2011, were recognized because the carrying value of certain exploration and evaluation assets and property and equipment exceeded their recoverable amounts and certain leases for exploration and evaluation assets and property and equipment were expired.

Loss and Operating Loss

The Company's loss for the current quarter was $9,453,000 or $0.063 per share, compared to a loss of $8,430,000 or $0.069 per share for the same quarter in 2011. The loss differential was primarily due to lower revenues and the increase in finance costs and amortization, depletion and impairment losses.

The Company's operating loss for the current quarter was $1,597,000, compared to $1,174,000 for Q4 2011. The increase was primarily due to lower revenues and the increase in finance costs. This was partly offset by the decrease in general and administrative expenses.

DEJOUR ENERGY INC.
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INVESTMENT AND INVESTMENT EFFICIENCIES

CAPITAL EXPENDITURES

Dejour is committed to future growth through its strategy to implement a full-cycle exploration and development program, augmented by strategic acquisitions with exploitation upside.

During the year ended December 31, 2012, Dejour incurred $2.2 million on drilling and completion operations. Equipment and facility expenditures were $1.4 million. The balance of $0.8 million was mostly related to the capitalization of general and administrative costs and lease rentals on its oil and gas interests.

During the year ended December 31, 2011, Dejour incurred $4.4 million on drilling and completion operations. Equipment and facility expenditures were $3.0 million. The balance of $1.0 million was mostly related to the capitalization of general and administrative costs and lease rentals on its oil and gas interests.

Additions to property and equipment and exploration and evaluation assets:

	Year ended December 31, 2012		Year ended December 31, 2011		
	$	% of total	$	% of total	% change
Land acquisition and retention	265,000	5.9%	242,000	2.9%	10%
Drilling and completion(1)	2,179,000	48.6%	4,398,000	52.6%	-50%
Facility and pipelines	1,388,000	30.9%	2,949,000	35.3%	-53%
Capitalized general and administrative	646,000	14.4%	742,000	8.9%	-13%
Other assets	7,000	0.2%	29,000	0.3%	-76%
	4,485,000	100.0%	8,360,000	100.0%	-46%

(1) excludes non-cash capital expenditures of $6,466,850 (US$6,500,000) related to joint venture financing (see 'Financial Contract' section of the MD&A for details)

LAND HOLDINGS

As at December 31, 2012, Dejour owned 117,676 net acres of undeveloped land, representing an approximate 12% increase compared to 104,856 net acres at December 31, 2011. Dejour's landholdings of developed land as at December 31, 2012 was increased by approximate 21% compared to its landholdings at December 31, 2011. The increase for both undeveloped and developed land was the result of addition of net acres to the Company's current landholdings in the U.S. through the acquisition of certain undeveloped lands from a joint venture partner in the normal course of business. This was offset by the expiration of certain leases during the year.

DEJOUR ENERGY INC.
RESOURCEFUL. ENTERPRISING.

The following table summarized Dejour's land holdings as at December 31, 2012 and 2011:

Landholdings	As at December 31, 2012		As at December 31, 2011		Percent change	
(in acres)	Gross	Net	Gross	Net	Gross	Net
Developed	19,564	12,609	17,455	10,412	12%	21%
Undeveloped	167,751	117,676	221,894	104,856	(24%)	12%
Total	187,315	130,285	239,349	115,268	(22%)	13%

RESERVES

AJM Deloitte, independent petroleum engineering consultants based in Calgary, Alberta were retained by the Company to evaluate its Canadian properties. Gustavson Associates, an independent petroleum engineering consultants based in Boulder, Colorado were retained by the Company to evaluate its US properties. The Company has a Reserves Committee which oversees the selection, qualifications and reporting procedures of the independent engineering consultants. Reserves as at December 31, 2012 were determined using the guidelines and definitions set out under National Instrument 51-101 ("NI 51-101").

The following table summarizes the Company's gross reserves at December 31, 2012:

Summary of Gross Reserves (Canada and US)	Oil (Mbbl)	Gas (Mmcf)	NGL's (Mbbl)	Oil Equivalent (Mboe)	FDC Costs (in thousands of dollars) (Mboe)
Proved					
Developed producing	299	791	18	448	-
Developed Non-Producing	-	254	21	63	153
Undeveloped	-	74,745	7,535	19,992	126,750
Total Proved	299	75,790	7,574	20,503	126,903
Probable	65	104,200	10,475	27,908	202,455
Total Proved and Probable	364	179,990	18,049	48,411	329,358

Future development capital ("FDC") expenditures included in the reserve evaluation for total proved reserves are expected to be spent as follows: $11.0 million in 2013, $22.5 million in 2014 and $93.4 million thereafter. FDC included for proved plus probable reserves are expected to be spent as follows: $11 million in 2013, $22.5 million in 2014 and $295.9 million thereafter.

The following table outlines the change in the Company's gross reserves year-over-year:

Reserves Reconciliation	Oil		Gas		Natural Gas Liquids		Combined	
	Total Proved (Mbbl)	Proved + Probable (Mbbl)	Total Proved (Mmcf)	Proved + Probable (Mmcf)	Total Proved (Mbbl)	Proved + Probable (Mbbl)	Total Proved (Mboe)	Proved + Probable (Mboe)
Balance, December 31, 2011	408	648	68,034	157,159	6,724	15,669	18,471	42,511
Technical revisions	(39)	(214)	8,154	23,230	850	2,381	2,170	6,038
Net changes	369	434	76,188	180,389	7,574	18,050	20,641	48,549
Production	(70)	(70)	(399)	(399)	(1)	(1)	(138)	(138)
Balance, December 31, 2012	299	364	75,789	179,990	7,573	18,049	20,503	48,411

DEJOUR ENERGY INC.
RESOURCEFUL. ENTERPRISING.

The following table outlines forecasted future prices that Dejour has used in their evaluation of the Company's reserves at December 31, 2012, as determined by the independent engineers who evaluated the Company's US and Canadian properties:

Future Commodity Price Forecast	Crude Oil	Natural Gas		Condensate	
	(Edmonton Par)	(AECO)	(Henry Hub)	(Edmonton Pentanes Plus)	USD/CAD Exchange
	Cdn$/bbl	Cdn$/mmbtu	US$/mmbtu	Cdn$/bbl	US$/Cdn$
2013	85.00	3.20	2.33	89.25	0.9949
2014	84.70	3.75	2.81	88.95	0.9949
2015	89.45	4.05	3.02	93.90	0.9949
2016	91.20	4.35	3.21	95.75	0.9949
2017	89.80	4.65	3.46	94.30	0.9949
Five year average	88.03	4.00	2.97	92.43	0.9949

The following table is a net present value summary (before tax) as at December 31, 2012:

Net Present Value Summary (Before Tax) (in thousands of dollars)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%
	$	$	$	$
Proved				
Developed producing	10,716	9,340	8,324	7,546
Developed Non-Producing	868	554	399	310
Undeveloped	221,259	96,719	46,953	22,700
Total Proved	232,843	106,613	55,676	30,556
Probable	336,571	112,212	43,211	17,640
Total Proved and Probable	569,414	218,825	98,887	48,196

The following table is a net present value summary (after tax) as at December 31, 2012:

Net Present Value Summary (After Tax) (in thousands of dollars)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%
	$	$	$	$
Proved				
Developed producing	10,514	9,193	8,207	7,448
Developed Non-Producing	625	406	294	228
Undeveloped	153,590	67,708	32,583	15,146
Total Proved	164,729	77,307	41,084	22,822
Probable	235,421	79,279	30,389	12,126
Total Proved and Probable	400,150	156,586	71,473	34,948

CAPITAL RESOURCES AND LIQUIDITY

GOING CONCERN, BANK CREDIT FACILITY, AND SUBSEQUENT EVENT

The financial statements were prepared on a going concern basis. The going concern basis assumes that the Company will continue in operation for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business. The Company has a working capital deficiency of $8,557,281 (of which $5,956,749 is represented by its 'bank line of credit') and accumulated deficit of $88,262,350.

Subsequent to December 31, 2012, DEAL was informed by its Canadian Bank ("Bank") that the value of the petroleum and natural gas reserves assigned to the Bank by the Company as partial security for its $6,050,000 (December 31, 2012 - $5,956,749) revolving line of credit was deficient for loan collateral purposes. On March 28, 2013, DEAL signed a new "Commitment Letter" with the Bank to renew its $5,950,000 (December 31, 2012 - $5,956,749) revolving operating demand loan under the following terms and conditions:

(a) "Credit Facility "A" – Revolving Operating Demand Loan - $3,700,000, to be used for general corporate purposes, ongoing operations, capital expenditures, and acquisition of additional petroleum and natural gas assets. Interest on Credit Facility "A" is at Prime + 1% payable monthly and all amounts outstanding are payable on demand any time, and

(b) Credit Facility "B" – Non-Revolving Demand Loan - $2,250,000. Interest on Credit Facility "B" is at Prime + 3 1/2% payable monthly. Monthly principal payments of $200,000 are due and payable commencing March 26, 2013 with all amounts outstanding under Credit Facility "B" ($1,450,000) due and payable in full on June 30, 2013.

Collateral for Credit Facilities "A" and "B" (the "Credit Facilities") is provided by a $10,000,000 first floating charge over all the assets of DEAL, a general assignment of DEAL's book debts, a $10,000,000 debenture with a first floating charge over all the assets of the Company and an unlimited guarantee provided by Dejour USA. The Credit Facilities are subject to bank renewal on or before June 30, 2013.

Prior to each advance under the Credit Facilities, DEAL is required to (i) provide the Bank with certain additional security required by the Bank; (ii) satisfy the Bank that no further default or event of default exists and that no material adverse effect has occurred with respect to DEAL, any guarantor or the collateral; (iii) satisfy the Bank that all representations and warranties of DEAL and all guarantors are true and correct; and (iv) execute any other document that may be reasonably requested by the Bank.

Further, in the event the Company accesses the debt or equity markets to source cash during the period from March 26, 2013 to June 30, 2013, or sells certain assets for cash, then the proceeds will be applied as follows: (i) full repayment of the balance outstanding under Credit Facility "B" on or before June 30, 2013 and (ii) a shortfall, if any, between the amount of Credit Facility "A" at June 30, 2013 and the underlying value of the lender's collateral at that date.

Under the terms of the facility, DEAL is required to maintain an adjusted working capital ratio of greater than 1:1 at all times. The working capital ratio is defined as the ratio of (i) current assets less unrealized hedging gains to (ii) accounts payable less unrealized hedging losses.

The Company's ability to continue as a going concern is dependent upon attaining profitable operations and obtaining sufficient financing to meet obligations and continue exploration and development activities. There is no assurance that these activities will be successful. These material uncertainties cast substantial doubt upon the Company's ability to continue as a going concern.

CASH BALANCES

The Company had cash and cash equivalents of $1,508,000 as at December 31, 2012.

FINANCIAL CONTRACT

On December 31, 2012, Dejour USA entered into a financial contract with an arm's length U.S. oil and gas drilling fund ("Drilling Fund") to drill three wells and complete up to four wells ("the Tranche 1 Wells") in the State of Colorado. By agreement:

(a) Dejour USA contributed four natural gas well spacing units, including one drilled and cased well with a cost of US$1,147,779;
(b) The Drilling Fund contributed US$6,500,000 cash directly to a drilling company as prepaid drilling costs;
(c) Dejour USA will earn a "before payout" working interest of 10% to 14% and an "after payout" working interest of 28% to 39% in the net operating profits from the Tranche 1 Wells based on the "actual cash invested in the drilling program;
(d) The Drilling Fund has the right to require that Dejour USA purchase the Drilling Fund's entire working interest in the Tranche 1 Wells 36 months after the commencement of production from the initial Tranche 1 Well, in the event a minimum rate of return, as defined, is not achieved. In the event the Drilling Fund exercises its right, the purchase price to be paid by Dejour USA will equal 75% of the Drilling Fund's actual investment less 75% of the Drilling Fund's share of working interest net profits from the Tranche 1 Wells, if any, for the 36-month period, plus a "top-up" amount so that the Drilling Fund earns a minimum 8% return, compounded annually and applied on a monthly basis, on 75% of its original investment over the 36-month period; and
(e) The Drilling Fund has the right to require Dejour USA to purchase all of the Drilling Fund's interest in the Tranche 1 Wells if at any time Dejour USA plans to divest of greater than 51% of its Working Interest in the Tranche 1 Wells and resigns as Operator (a "Change of Control Event"). The purchase price is equal to the future net profit from the "Proven and Probable Reserves" attributable to the Drilling Funds working interest in the Tranche 1 Wells, discounted at 12%, as determined by a third party evaluator acceptable to both parties.

Dejour USA considers the transaction to be a financial contract liability as the risks and rewards of ownership have not been substantially transferred at the Agreement date. On December 31, 2012 the Drilling Fund had advanced US$6,500,000 to a drilling contractor for the Tranche 1 wells. On the Drilling Fund financing advance, the Company increased property and equipment and financial contract liability by $6,466,850 (US$6,500,000). On initial recognition, the Company imputed its borrowing cost of 8.4% based on the estimated timing and amount of operating profit using the independent reserve engineer's estimated future cash flows for the Drilling Funds working interest in the Tranche 1 Wells. Subsequent to initial measurement the financial contract liability will be increased by the imputed interest expense and decreased by the Drilling Fund's net operating profit from the Tranche 1 Wells. Any changes in the estimated timing and amount of the net operating profit cash flows will be discounted at the initial imputed interest rate with any change in the recognized liability recognized as a gain (loss) in the period of change. The Company has estimated the current portion of the obligation based on the expected net operating profit to be paid to the Drilling Fund in the next twelve months.

	US$	CAD$
Loan advance	6,500,000	6,466,850
Less: Current portion of financial contract liability	(1,311,969)	(1,305,278)
Non-current portion of financial contract liability	5,188,031	5,161,572

The estimated reduction in the financial contract liability is estimated to be:

	US$	CAD$
2013	1,311,969	1,305,278
2014	917,943	913,261
2015	602,166	599,095

WORKING CAPITAL POSITION

As at December 31, 2012	$
Working capital deficit	(8,557,000)
Non-cash warrant liability	1,425,000
Non-cash current portion of financial contract liability	1,305,000
Net cash working capital deficit	(5,827,000)
Add: Bank line of credit	5,957,000
Net cash working capital (excluding bank line of credit)	130,000

As at December 31, 2012, the Company had a working capital deficit of $8,557,000. Excluding the non-cash warrant liability of $1,425,000 related to the fair value of US$ denominated warrants issued in previous equity financings and the non-current portion of financial contract liability of $1,305,000, the net working capital deficit was $5.8 million. The majority of the working capital deficit relates to the $6.0 million outstanding bank line of credit, with a $0.7 million credit limit remaining.

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

As noted in the GOING CONCERN, BANK CREDIT FACILITY, and SUBSEQUENT EVENT section of this MD&A, on March 28, 2013, DEAL signed a new “Commitment Letter” with the Bank to renew its $5,950,000 (December 31, 2012 - $5,956,749) revolving operating demand loan under the following terms and conditions:

(a) “Credit Facility “A” – Revolving Operating Demand Loan - $3,700,000, to be used for general corporate purposes, ongoing operations, capital expenditures, and acquisition of additional petroleum and natural gas assets. Interest on Credit Facility “A” is at Prime + 1% payable monthly and all amounts outstanding are payable on demand any time; and
(b) Credit Facility “B” – Non-Revolving Demand Loan - $2,250,000. Interest on Credit Facility “B” is at Prime + 3 1/2% payable monthly. Monthly principal payments of $200,000 are due and payable commencing March 26, 2013 with all amounts outstanding under Credit Facility “B” ($1,450,000) due and payable in full on June 30, 2013.

Collateral for Credit Facilities “A” and “B” (the “Credit Facilities”) is provided by a $10,000,000 first floating charge over all the assets of DEAL, a general assignment of DEAL’s book debts, a $10,000,000 debenture with a first floating charge over all the assets of the Company and an unlimited guarantee provided by Dejour USA. The Credit Facilities are subject to bank renewal on or before June 30, 2013.

Prior to each advance under the Credit Facilities, DEAL is required to (i) provide the Bank with certain additional security required by the Bank; (ii) satisfy the Bank that no further default or event of default exists and that no material adverse effect has occurred with respect to DEAL, any guarantor or the collateral; (iii) satisfy the Bank that all representations and warranties of DEAL and all guarantors are true and correct; and (iv) execute any other document that may be reasonably requested by the Bank.

Further, in the event the Company accesses the debt or equity markets to source cash during the period from March 26, 2013 to June 30, 2013, or sells certain assets for cash, then the proceeds will be applied as follows: (i) full repayment of the balance outstanding under Credit Facility “B” on or before June 30, 2013 and (ii) a shortfall, if any, between the amount of Credit Facility “A” at June 30, 2013 and the underlying value of the lender’s collateral at that date.

Under the terms of the facility, DEAL is required to maintain an adjusted working capital ratio of greater than 1:1 at all times. The working capital ratio is defined as the ratio of (i) current assets less unrealized hedging gains to (ii) accounts payable less unrealized hedging losses.

Subsequent to the year-end, the Company has initiated discussions with a number of financial advisory firms to address the Company’s financing requirements on a timely basis.

CAPITAL RESOURCES

a) Canada

At Drake/Woodrush, the Company successfully completed and tied into production a 3rd oil well and continued to optimize the waterflood implemented in 2011. In Q3 2013, the Company intends to conduct a geological and operational review of Drake/Woodrush in an effort to increase operating efficiencies and define additional drilling targets for reserves and production expansion.

b) United States

Industry activity in the Piceance Basin of Colorado continues to increase. Several major US companies and one large Canadian company are currently drilling and completing over 10 wells within a 5 mile radius of the Company's Kokopelli acreage in the eastern extremity of the Piceance. At Kokopelli, the Company has started a drilling program to further develop the Williams Fork natural gas zone at 9,000 ft. consisting of the drilling of 3 wells and the completion and related tie-in of 4 wells. The total cost of the program will be approximately US$8,200,000. Funding for the program has been primarily provided by a US$6,500,000 financing contract with an industry Drilling Find. Under the terms of the industry-standard agreement, the Company will earn a "before-payout" ('BPO') working interest of 10% to 14% and an "after payout" ('APO') working interest of 28% to 39%. Incremental production from the drilling program is expected to be 14MMcf/d, or 2,400 BOE/d (gross) and 2.8 MMcf/d, or 430 BOE/d (net).

The agreement with the Drilling Fund provides for an additional two tranches of drilling under the following terms and conditions:

- The Drilling Fund will have the right, but not the obligation, to invest up to an additional US$8,500,000 for a total of US$15,000,000 in two additional tranches;
- Tranche 3 estimated between US$4 to US$5 million, can only be initiated within two years after committing to the full US$4,000,000 to US$5,000,000 in Tranche 2;
- Dejour will receive a 10% BPO carried interest in all wells or partial wells drilled by the Drilling Fund, reverting to a 32.5% APO working interest. "Payout" to the Drilling Fund is defined as 125% of the capital investment amount on a tranche by tranche basis;
- Tranche 2 and 3 wells will be funded only in conjunction with Dejour's plans for development of Kokopelli. If, for example, no development is planned, the Drilling Fund's option will remain in effect until Dejour presents a drilling plan to the Drilling Fund; and
- The Drilling Fund does not earn the right to "put" its Tranche 2 and 3 working interests back to the Company under any circumstances.

In addition to the capital provided by the Drilling Fund, the Company has been approached in Q1 2013 by a number of senior industry financiers wishing to pursue joint ventures to further develop the Company's

Piceance Basin assets. Presently, the Company has signed "Confidentiality Agreements" ("CA") with two of these funding sources and is currently negotiating the terms of a third CA.

CONTRACTUAL OBLIGATIONS

As of December 31, 2012, and in the normal course of business we have obligations to make future payments, representing contracts and other commitments that are known and committed.

(in thousands of dollars)	2013	2014	2015	2016	2017	Thereafter	Total
	$	$	$	$	$	$	$
Operating lease obligations	229	164	48	-	-	Nil	441
Bank line of credit	5,957	-	-	-	-	Nil	5,957
Financial contract liability[1]	1,305	913	599	-	-	Nil	2,817
Total	7,491	1,077	647	-	-	Nil	9,215

(1) This represents the Company's obligations over the 36-month put option period until it expires. If the put option expires unexercised, both the property and equipment and related liability of approximately $3,650,000 will be derecognized. See Note 11 to the consolidated financial statements for details.

RELATED PARTY TRANSACTIONS

During the years ended December 31, 2012 and 2011, the Company entered into the following transactions with related parties:

(a) Compensation awarded to key management included a total of salaries and consulting fees of $1,194,087 (2011 - $1,771,981) and non-cash stock-based compensation of $412,049 (2011 - $451,071). Key management includes the Company's officers and directors. The salaries and consulting fees are included in general and administrative expenses. Included in accounts payable and accrued liabilities at December 31, 2012 is $Nil (December 31, 2011 - $396,618) owing to the companies controlled by the officers of the Company.

(b) The Company incurred a total of $Nil (2011 - $2,301) in finance costs to a company controlled by an officer of the Company.

(c) Included in interest and other income is $30,000 (2011 - $30,000) received from the companies controlled by officers of the Company for rental income.

(d) In December 2009, a company controlled by the CEO of the Company ("HEC") became a 5% working interest partner in the Woodrush property. Included in accounts payable and accrued liabilities at December 31, 2012 is $20,288 (December 31, 2011 - $53,668) owing to HEC.

(e) With respect to the private placement of 11,010,000 units issued at US$0.30 per unit completed in February 2011, directors and officers of the Company purchased 2,000,000 units of this offering (see Note 12 to the consolidated financial statements for details).

(f) In December 2011, HEC exercised 250,000 warrants with an exercise price of US$0.35 each that were issued in February 2011.

(g) In January 2012, directors and officers of the Company exercised 750,000 warrants with an exercise price of US$0.35 each that were issued in February 2011.

(h) On December 31, 2012, Dejour USA entered into a financial contract with a U.S. oil and gas drilling fund ("Drilling Fund") whereby the parties agreed to form an industry-standard drilling partnership for purposes of drilling three wells and completing four wells in the State of Colorado (note 11). A director of the Company provides investment advice for a fee to the Drilling Fund. The director abstained from voting when the Board of Directors approved the Company signing a financial contract with the Drilling Fund.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has no material undisclosed off-balance sheet arrangements that have or are reasonably likely to have, a current or future effect on our results of operations or financial condition at December 31, 2012.

SELECTED ANNUAL INFORMATION

The following table summarizes key financial and operating information over the three most recently completed financial year:

(in thousands of dollars, except per unit amounts)	2012	2011	2010
Gross oil and gas revenues	6,882	8,824	8,086
Income (loss)			
Per share - basic ($/common share)	(0.083)	(0.092)	(0.051)
Per share - diluted ($/common share)	(0.083)	(0.092)	(0.051)
Total assets	27,573	29,438	30,413
Production (BOE/d)	372	421	487
Average realized price ($/BOE)	50.59	57.49	45.53
Operating netback ($/BOE)	15.10	30.70	23.48
Netback as a percentage of sales	29%	53%	52%

The Company has not declared any cash dividends since inception.

SUMMARY OF QUARTERLY RESULTS

The following table summarizes key financial and operating information by quarter for the past eight quarters ending December 31, 2012:

(in thousands of dollars, except per unit amounts)	2012 Q4	2012 Q3	2012 Q2	2012 Q1	2011 Q4	2011 Q3	2011 Q2	2011 Q1
Gross oil and gas revenues	1,630	1,552	1,771	1,928	2,478	2,947	1,816	1,584
Income (loss)								
Per share - basic ($/common share)	(0.063)	(0.009)	(0.004)	(0.003)	(0.069)	(0.003)	(0.002)	(0.018)
Per share - diluted ($/common share)	(0.063)	(0.009)	(0.004)	(0.003)	(0.069)	(0.003)	(0.002)	(0.018)
Total assets	27,573	30,606	31,054	28,030	29,438	30,754	31,409	32,190
Production (BOE/d)	319	346	406	416	471	514	287	408
Average realized price ($/BOE)	55.55	48.73	47.88	50.95	57.15	62.34	69.44	43.13
Operating netback ($/BOE)	22.43	3.45	17.30	17.07	27.48	35.31	38.11	24.08
Netback as a percentage of sales	35%	7%	36%	33%	48%	57%	55%	53%

The fluctuations in Dejour's revenue and income (loss) from quarter to quarter are primarily caused by variations in production volumes, realized oil and natural gas prices and the related impact on royalties and operating and transportation expenses. Please refer to the Results of Operations section of this MD&A for detailed discussion of changes from the 4th quarter of 2012 to the 4th quarter of 2011, and to the Company's previously issued interim and annual MD&A for changes in prior quarters.

BUSINESS RISKS

Dejour's exploration and production activities are concentrated in the Northeastern B.C. portion of the competitive Western Canadian Sedimentary Basin and the Piceance Basin of Central United States, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers and intermediate and senior producers to the much larger integrated petroleum companies. Dejour is subject to a number of risks which are also common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, production of oil and gas in commercial quantities, marketability of oil and gas produced, fluctuations in commodity prices, financial and liquidity risks and environmental and safety risks.

In order to reduce exploration risk, Dejour employs highly qualified and motivated professional employees who have demonstrated the ability to generate quality proprietary geological and geophysical prospects. To maximize drilling success, Dejour explores in areas that afford multi-zone prospect potential, targeting a range of shallower low to moderate risk prospects with some exposure to select deeper high-risk prospects with high-reward opportunities.

Dejour has retained an independent engineering consulting firm that assists the Company in evaluating recoverable amounts of oil and gas reserves. Values of recoverable reserves are based on a number of variable factors and assumptions such as commodity prices, projected production, future production costs and government regulation. Such estimates may vary from actual results.

The Company mitigates its risk related to producing hydrocarbons through the utilization of the most advanced technology and information systems. In addition, Dejour strives to operate the majority of its prospects, thereby maintaining operational control. The Company does rely on its partners in jointly owned properties that Dejour does not operate.

Dejour is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company's control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in the Canada-United States currency exchange rate, which in turn respond to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals. Dejour may periodically use futures and options contracts to hedge its exposure against the potential adverse impact of commodity price volatility.

Exploration and production for oil and gas is very capital intensive. As a result, the Company relies on equity markets as a source of new capital. In addition, Dejour utilizes bank financing to support on-going capital investment. Funds from operations also provide Dejour with capital required to grow its business. Equity and debt capital is subject to market conditions and availability may increase or decrease from time to time. Funds from operations also fluctuate with changing commodity prices.

SAFETY AND ENVIRONMENT

Oil and gas exploration and production can involve environmental risks such as pollution of the environment and destruction of natural habitat, as well as safety risks such as personal injury. The Company conducts its operations with high standards in order to protect the environment and the general public. Dejour maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, as well as industry standards and government regulations.