DEJOUR ENERGY INC.

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ANNUAL INFORMATION FORM
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2012

March 28, 2013

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PRELIMINARY NOTES

In this Annual Information Form ("AIF"), Dejour Energy Inc. is referred to as "**Dejour**" or the "**Company**" and includes reference to subsidiaries, unless otherwise stated. All information contained herein is as at December 31, 2012 or the date of the AIF, being March 28, 2013, unless otherwise stated.

Financial Statements

This AIF should be read in conjunction with the Company's audited consolidated financial statements and management's discussion and analysis for the 12 months ended December 31, 2012. The audited financial statements and management's discussion and analysis are available under the Company's profile on the SEDAR website at www.sedar.com. The financial statements of the Company for the year ended December 31, 2012 are prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC").

Currency and Exchange Rates

All sums of money which are referred to in this AIF are expressed in lawful money of Canada, unless otherwise specified. The following table sets forth, for each of the years indicated, as reported by the Bank of Canada, the exchange rate of United States dollars into Canadian dollars at the end of each such year, the average exchange rate during each such year and the range of high and low rates for each such year.

	Years Ended December 31		
	2012	**2011**	**2010**
High	1.0418	1.0604	1.0559
Low	0.9710	0.9449	1.0051
Average	0.9996	0.9891	1.0305
Closing	0.9949	1.0170	0.9946

The Company has adopted the standard of 6 Mcf:1 boe when converting natural gas to barrels of oil equivalent. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Readers should read the "Additional Information and Advisory" section located at the end of this document, which provide information on Forward-Looking Statements, Abbreviations, Oil & Gas Information, and Presentation of Oil and Gas Reserves and Production Information and Conversion Factors.

CORPORATE STRUCTURE

Name, Address and Incorporation

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-for-three-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-AMEX**") 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.

Intercorporate Relationships

The Company has four 100% owned subsidiaries:

- Dejour Energy (USA) Corp. ("**Dejour USA**"), a Nevada corporation, holds Dejour's United States oil and gas interests,

- Dejour Energy (Alberta) Ltd. ("**DEAL**"), an Alberta corporation, holds its Canadian oil and gas interests,

- Wild Horse Energy Ltd. ("**Wild Horse**"), an inactive Alberta corporation (90% owned by the Company and another 10% owned through DEAL), which is currently inactive, and

- 0855524 B.C. Ltd. ("**0855524")**, a British Columbia Corporation, which is currently inactive.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year History

2012

In 2012, the Company continued its focus on production optimization of the Drake/Woodrush oilfield in northeastern British Columbia, Canada, while completing drilling and production activities at the Kokopelli and South Rangely bases in the Piceance Basin of Western Colorado.

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

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 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.

2011

In 2011, the Company optimized production at the Drake/Woodrush property, and completed pre-drilling and lease curing activities at Kokopelli. The Company also drilled a successful discovery well at South Rangely.

Key achievements were:

1. Successful implementation and expansion of the Halfway "E" oil pool waterflood on the Company's Woodrush property;

2. Obtained a $7 million line of credit from a Canadian bank to refinance the bridge loan and to provide funds for general corporate purposes;

3. Generated positive operating cash flow for the second half of the year;

4. Completed all requirements for drilling on the Company's federal leases at Gibson Gulch, Piceance Basin, Colorado, resulting in the first drilling permits being issued in the fourth quarter of the year; and

5. Completed and tested a discovery well at South Rangely. After the well was successfully fractured and stimulated, the well flowed rich gas from the Mancos "B" Sand in commercial quantities.

2010

During the year, the Company achieved the following:

1. Extended the limits of the Woodrush halfway pool by drilling three successful development wells in 2010;

2. Received approval from the British Columbia Oil and Gas Commission to implement a waterflood in the Halfway "E" oil pool at Woodrush and began project implementation in October;

3. Raised gross proceeds of $4.7 million in equity, allowing the Company to support the development of oil and gas properties in the Drake/Woodrush properties; and

4. Obtained a bridge loan credit facility of up to $5 million, allowing the Company to refinance its existing bank facility and fund its working capital and capital expenditures.

DESCRIPTION OF THE BUSINESS

General

The Company is in the business of acquiring, exploring and developing energy projects with a focus on oil and gas exploration in Canada and the United States.

The Company holds approximately 130,000 net acres of oil and gas leases in the following regions:

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

Summary

Over the past few years, 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 moderate to high risk exploration potential.

Specialized Skill and Knowledge. Exploration for and development of petroleum and natural gas resources requires specialized skills and knowledge including in the areas of petroleum engineering, geophysics, geology and title. The Company and its subsidiaries have obtained personnel with the required specialized skills and knowledge to carry out their respective operations. While the current labour market in the industry is highly competitive, the Company expects to be able to attract and maintain appropriately qualified employees for fiscal 2012.

Cycles. All of the Company's operations in Canada are affected by seasonal operating conditions. DEAL holds properties in northwestern Alberta and northeastern British Columbia which are accessible to heavy equipment in winter only when the ground is frozen, typically between December to early April. For this reason drilling and pipeline construction ceases over the remainder of the year, limiting growth to winter only. Production operations continue year round in these areas once production is established. The prices that the Company will receive for oil and gas production in the future are weighted to world benchmark prices and may be adversely affected by mild weather conditions. In 2007 and the first half of 2008 higher demand increased world commodity prices. Recently there has been a significant change in the supply demand balance and commodity prices have fallen dramatically. The Company expects this condition to persist for several months but the Company believes that a balance between production and consumption and a stable price environment will be reestablished by the end of 2012. See *"Risk Factors – Risks related to operating an exploration, development and production company".*

Environmental Protection. The Company's operations are subject to environmental regulations (including regular environmental impact assessments and permitting) in the jurisdictions in which it operates. Such regulations cover a wide variety of matters, including, without limitation, emission of greenhouse gases, prevention of waste, pollution and protection of the environment, labour regulations and worker safety. Under such regulations there are preventative obligations, clean-up costs and liabilities for toxic or hazardous substances which may exist on or under any of its properties or which may be produced as a result of its operations. Environmental legislation and legislation relating to exploration and production of oil and natural gas will require stricter standards and enforcement, increased fines and penalties for non-compliance, more stringent environmental assessments of proposed projects and a heightened degree of responsibility for companies and their directors and employees. Such stricter standards could impact the Company's costs and have an adverse effect on results of operations. The Company expects to incur abandonment and site reclamation costs as existing oil and gas properties are abandoned and reclaimed; however, the Company does not anticipate making material expenditures beyond normal compliance with environmental regulations in 2012 and future years.

Employees. The Company had an average of 17 full-time equivalent of employees and consultants during 2012.

Social or Environmental Policies. The health and safety of employees, contractors and the public, as well as the protection of the environment, is of utmost importance to the Company. The Company endeavours to conduct its operations in a manner that will minimize adverse effects of emergency situations by:

- complying with government regulations and standards;
- following industry codes, practices and guidelines;
- ensuring prompt, effective response and repair to emergency situations and environmental incidents; and
- educating employees and contractors of the importance of compliance with corporate safety and environmental rules and procedures.

The Company believes that all Company personnel have a vital role in achieving excellence in environmental, health and safety performance. This is best achieved through careful planning and the support and active participation of everyone involved.

Competitive Conditions. The Company operates in geographical areas where there is strong competition by other companies for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel. The Company's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators, many of whom have greater financial and personnel resources than the Company. The Company's ability to acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers is dependent upon developing and maintaining close working relationships with its current industry partners and joint operators, and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

US Oil and Gas Interests

Kokopelli, Piceance Basin

During 2012, the Company drilled an initial well into the Williams Fork liquids-rich natural gas formation at Kokopelli to hold its 2,200 acres of leasehold interests. The Company also entered into a financial contract with an industry Drilling Fund to complete the initial well and drill, complete, and tie-in an additional 3 wells. The Drilling Fund's investment of US$6,500,000 represents about 80% of the total program costs of US$8,200,000. The primary producing geological horizons are the Williams Fork and Lower Mancos zones.

The Company's 4-well drilling and completion program at Kokopelli will focus strictly on the Williams Fork formation and expected to be completed by June 30, 2013.

South Rangely, Piceance Basin

In June 2011, the Company drilled and cased an evaluation well on this 5,500 gross acre (4,490 net acre) lease which is located just south of the Rangely field. The well was drilled and casing set on approximately 90 feet of gross Mancos "B" Sand and later successfully fractured and stimulated. The well flowed rich gas from the Mancos "B" Sand in commercial quantities. Analysis of the gas showed a higher natural gas liquid ("NGL") yield from the South Rangely discovery than that expected from our NGL development at Kokopelli.

West Grand Valley, Piceance Basin – Evolution of the Niobrara/Mancos Shale Resource Play

On the Company's West Grand Valley property, it 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 that is located in an area of active drilling by EnCana, Laramie Partners II and Axia. Success in developing the gas in the Lower Mancos (Niobrara) section has revitalized drilling interest in this area of the Piceance Basin.

Future Exploration and Evaluation

- North Rangely – This 21,000 acre (gross) project located north of the Rangely Field, is prospective for oil in the Lower Mancos (Niobrara), Dakota, Morrison and Phosphoria formations.

Additionally, Dejour holds approximately 123,000 net acres prospective for oil and gas exploitation in Colorado and Utah.

<u>Canadian Activities</u>

Drake/Woodrush Field

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

DEAL holds approximately 7,000 net acres concentrated in the Peace River Arch.

<u>Production and Development Projects</u>

Woodrush/Drake

In December 2010, a waterflood project application was expedited and approval was received. The project was implemented in early 2011 with water injection commencing in March 2011. In the first quarter of 2011, gross production from the field was reduced to approximately 544 barrels of oil equivalent/day ("BOED") (408 BOED net) in response to the decreasing pressure in the Halfway oil sand. In October, Dejour received approval to operate the waterflood on a voidage replacement basis and in December drilled a third production well while increasing total injection from 1200 BWPD to 2400 BWPD. The start-up and subsequent enhancement of the waterflood marked the end of major capital investments in Woodrush. During 2012, Dejour concentrated efforts on optimizing injection and production in the waterflood, controlling cost and increasing margins on oil production. The reservoir reached fill up in the fourth quarter of 2012 and subsequent to achieving fill up oil production began increasing at a rate of approximately 25 barrels/day/month, a trend which continued through the first quarter of 2013.

<u>Uranium Properties</u>

The Company has a 10% carried interest and 1% Net Smelter Return on certain uranium exploration leases in Saskatchewan operated by Titan Uranium Inc.

RISK FACTORS

An investment in a company engaged in oil and gas exploration involves an unusually high amount of risk, both unknown and known, present and potential, including, but not limited to the risks enumerated below.

Our failure to successfully address the risks and uncertainties described below would have a material adverse effect on our business, financial condition and/or results of operations, and the trading price of our common stock may decline and investors may lose all or part of their investment. We cannot assure you that we will successfully address these risks or other unknown risks that may affect our business.

Risks related to commodity price fluctuations

The marketability and price of oil and natural gas are affected by numerous factors outside of the Company's control. Material fluctuations in oil and natural gas prices could adversely affect the Company's net production revenue and oil and natural gas operations.

Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond the Company's control, such as:

- the domestic and foreign supply of and demand for oil and natural gas;
- the price and quantity of imports of crude oil and natural gas;
- overall domestic and global economic conditions;
- political and economic conditions in other oil and natural gas producing countries, including embargoes and continued hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the level of consumer product demand;
- weather conditions;
- the impact of the U.S. dollar exchange rates on oil and natural gas prices; and
- the price and availability of alternative fuels.

The Company's ability to market its oil and natural gas depends upon its ability to acquire space on pipelines that deliver such commodities to commercial markets. The Company is also affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive governmental regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and net present value of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities.

Because world oil and natural gas prices are quoted in U.S. dollars, the Company's production revenues could be adversely affected by an appreciation of the Canadian dollar.

World oil and natural gas prices are quoted in U.S. dollars, and the price received by Canadian producers, including the Company, is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the U.S. dollar. Such material increases in the value of the Canadian dollar may negatively impact the Company's production revenues. Further material increases in the value of the Canadian dollar would exacerbate this potential negative impact and could have a material adverse effect on the Company's financial condition and results of operations. This increase in the exchange rate for the Canadian dollar and future Canadian/U.S. exchange rates could also negatively impact the future value of the Company's reserves as determined by independent petroleum reserve engineers.

Risks related to operating an exploration, development and production company

The Company's ability to execute projects will depend on certain factors outside of its control. If the Company is

unable to execute projects on time, on budget or at all, it may not be able to effectively market the oil and natural gas that it produces.

The Company manages a variety of small and large projects in the conduct of its business. The Company's ability to execute projects and market oil and natural gas will depend upon numerous factors beyond the Company's control, including:

- the availability of adequate financing;
- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in governmental regulations;
- the availability and productivity of skilled labour.

Because of these factors, the Company could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Oil and gas exploration has a high degree of risk and our exploration efforts may be unsuccessful, which would have a negative effect on our operations.

There is no certainty that the expenditures to be made by us in the exploration of our current projects, or any additional project interests we may acquire, will result in discoveries of recoverable oil and gas in commercial quantities. An exploration project may not result in the discovery of commercially recoverable reserves and the level of recovery of hydrocarbons from a property may not be a commercially recoverable (or viable) reserve that can be legally and economically exploited. If exploration is unsuccessful and no commercially recoverable reserves are defined, we would require to evaluate and acquire additional projects that would require additional capital, or we would have to cease operations altogether.

Cumulative unsuccessful exploration efforts could result in us having to cease operations.

The expenditures to be made by us in the exploration of our properties may not result in discoveries of oil and natural gas in commercial quantities. Many exploration projects do not result in the discovery of commercially recoverable oil and gas deposits, and this occurrence could ultimately result in us having to cease operations.

Oil and natural gas operations involve many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs for which the Company is not fully insured, the Company's business, financial condition, results of operations and prospects could be adversely affected.

The Company's involvement in the oil and natural gas exploration, development and production business subjects it to all of the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company. In accordance with industry practice, the Company is not fully insured against all of these risks. Although the Company maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs that could have a material adverse effect upon its financial condition. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. For instance, the Company does not have insurance to protect against the risk from terrorism. Oil and natural gas production operations are also subject to all of the risks typically associated with such operations, including encountering unexpected geologic formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks could have a material adverse effect on the Company’s business, financial condition, results of operations and prospects.

Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity.

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Oil and natural gas development activities, including seismic and drilling programs in northern Alberta and British Columbia, are restricted to those months of the year when the ground is frozen. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. In addition, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain, and additional seasonal weather variations will also affect access to these areas. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity during certain parts of the year.

The petroleum industry is highly competitive, and increased competitive pressures could adversely affect the Company’s business, financial condition, results of operations and prospects.

The petroleum industry is competitive in all of its phases. The Company competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than the Company. The Company's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage.

The Company does not control all of the assets that are used in the operation of its business and, therefore, cannot ensure that such assets will be operated in a manner favorable to the Company.

Other companies operate some of the assets in which the Company has an interest. As a result, the Company has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Company's financial performance. The Company's return on assets operated by others will therefore depend upon a number of factors that may be outside of the Company's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

The Company’s ability to market oil and natural gas depends on its ability to transport its product to market. If the Company is unable to expand and develop the infrastructure in the areas surrounding certain of its assets, it may not be able to effectively market the oil and natural gas that is produces.

Due to the location of certain of the Company's assets, both in Canada and the United States, there is minimal infrastructure currently available to transport oil and natural gas from the Company's existing and future wells to market. As a result, even if the Company is able to engage in successful exploration and production activities, it may not be able to effectively market the oil and natural gas that it produces, which could adversely affect the Company's business, financial condition, results of operations and prospects.

Demand and competition for drilling equipment could delay the Company's exploration and production activities, which could adversely affect the Company's business, financial condition, results of operations and prospects.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities. To the extent the Company is not the operator of its oil and natural gas properties, the Company will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

Title to the Company's oil and natural gas producing properties cannot be guaranteed and may be subject to prior recorded or unrecorded agreements, transfers, claims or other defects.

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Company's claim. A defect in the Company's title to any of its properties may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

The Company may be unable to meet all of the obligations necessary to successfully maintain each of the licenses and leases and working interests in licenses and leases related to its properties, which could adversely affect the Company's business, financial condition, results of operations and prospects.

The Company's properties are held in the form of licenses and leases and working interests in licenses and leases. If the Company or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. None of the obligations required to maintain each license or lease may be met. The termination or expiration of the Company's licenses or leases or the working interests relating to a license or lease may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Risks related to financing continuing and future operations

The Company has a working capital deficiency and will be required to raise capital through financings. We may not be able to obtain capital or financing on satisfactory terms, or at all.

As of December 31, 2012, the Company had a working capital deficiency of approximately $8.6 million. Excluding the non-cash warrant liability of $1.4 million related to the fair value of US$ denominated warrants issued in current and previous equity financings and the non-current portion of financial contract liability of $1.3 million, the working capital deficiency mainly consists of $6.0 million outstanding demand line of credit. On March 28, 2013, the Company renewed its revolving bank facility in the amount of $5.9 million. Under the terms of the revised agreement with the Bank, the Company is obligated to pay its Bank $1,450,000 on June 30, 2013. We expect to incur general and administration expenses of approximately $2.5 million over the next twelve months. We cannot assure you that debt or equity financing will be available to us, and even if debt or equity financing is available, it may not be on terms acceptable to us. Our inability to access sufficient capital for our operations and our June 30, 2013 Bank payment would have a material adverse effect on our business, financial condition, results of operations and prospects.

The Company anticipates making substantial capital expenditures for future acquisition, exploration, development and production projects. The Company may not be able to obtain capital or financing necessary to

support these projects on satisfactory terms, or at all.

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. Debt or equity financing, or cash generated by operations, may not be available to the Company or may not be sufficient to meet the Company’s requirements for capital expenditures or other corporate purposes. Even if debt or equity financing is available, it may not be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times, thereby causing the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations.

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and it is currently utilizing its bank line of credit to fund its working capital deficit. From time to time, the Company may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, not be able to take advantage of certain acquisition opportunities and reduce or terminate its level of operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, the Company's ability to expend the necessary capital to replace its reserves or to maintain its production will be impaired. If the Company's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on favourable terms.

Debt that the Company incurs in the future may limit its ability to obtain financing and to pursue other business opportunities, which could adversely affect the Company’s business, financial condition, results of operations and prospects.

From time to time, the Company may enter into transactions to acquire assets or equity of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Company's debt levels above industry standards for oil and natural gas companies of a similar size. Depending on future exploration and development plans, the Company may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. None of the Company's organizational documents currently limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time could impair the Company's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

The Company may be exposed to the credit risk of third parties through certain of its business arrangements. Non-payment or non-performance by any of these third parties could have an adverse effect on the Company’s financial condition and results of operations.

The Company may be exposed to third-party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures could have a material adverse effect on the Company’s financial condition and results of operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

Risks related to maintaining reserves and acquiring new sources of oil and natural gas

The Company's success depends on its ability to find, acquire, develop and commercially produce oil and natural gas, which is dependent on certain factors outside of the Company's control.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas. The Company has only recently commenced production of oil and gas. There is no assurance that the Company's other properties or future properties will achieve commercial production. Without the continual addition of new reserves, the Company's existing reserves and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire new suitable producing properties or prospects. No assurance can be given that the Company will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Company may determine that current market conditions, the terms of any acquisition or participation arrangement or pricing conditions may make such acquisitions or participations uneconomical, and further commercial quantities of oil and natural gas may not be produced, discovered or acquired by the Company, any of which could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Properties that the Company acquires may not produce as projected, and the Company may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities.

The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. However, the Company's review of acquired properties is inherently incomplete, as it generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken.

The Company's estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in the reserve estimates or the underlying assumptions may adversely affect the quantities and present value of the Company's reserves.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquid reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this AIF are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves, and such variations could be material.

In accordance with applicable securities laws, AJM Deloitte, (see "*Reserve Estimation and Economic Evaluation*" herein) and Gustavson Associates ("Gustavson"), (see "Reserves Evaluation Report" herein) have used both constant and forecast prices and costs in estimating the reserves and future net cash flows contained in their reports. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Company's oil and gas reserves will vary from the estimates contained in the AJM Deloitte and/or Gustavson reports, and such variations could be material. The reports are based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows set out in the reports will be reduced to the extent that such activities do not achieve the level of success assumed in the reports.

The Company's future oil and natural gas production may not result in revenue increases and may be adversely affected by operating conditions, production delays, drilling hazards and environmental damages.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Risks related to management of the Company

The Company may experience difficulty managing its anticipated growth.

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to attract and retain qualified management and technical personnel to meet the needs of its anticipated growth. The inability of the Company to deal with this growth could have a material adverse impact on its business, financial condition, results of operations and prospects.

The Company depends upon key personnel and the absence of any of these individuals could result in us having to cease operations.

While engaged in the business of exploring mineral properties, the nature of the Company's business, the Company's ability to continue its exploration of potential exploration projects, and to develop a competitive edge in the marketplace, depends, in large part, upon its ability to attract and maintain qualified key management and technical personnel. Competition for such personnel is intense and the Company may not be able to attract and retain such personnel.

Risks related to federal, state, local and other laws, controls and regulations

The Company is subject to complex federal, provincial, state, local and other laws, controls and regulations that could adversely affect the cost, manner and feasibility of conducting its oil and natural gas operations.

Oil and natural gas exploration, production, marketing and transportation activities are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Company's costs, any of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, in order to conduct oil and natural gas operations, the Company requires licenses from various governmental authorities. There can be no assurance that the Company will be able to obtain all of the licenses and permits that may be required to conduct operations that it may desire to undertake.

There is uncertainty regarding claims of title and rights of the aboriginal people to properties in certain portions of western Canada, and such a claim, if made in respect of the property or assets of the Company, could adversely affect the Company's business, financial condition, results of operations and prospects.

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. The Company is not aware that any claims have been made in respect of its property and assets; however, if a claim arose and was successful it would have an adverse effect on the Company's business, financial condition, results of operations and prospects.

The Company is subject to stringent environmental laws and regulations that may expose it to significant costs and liabilities, which could adversely affect the Company's business, financial condition, results of operations and prospects.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures, and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Environmental laws may result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise adversely affect the Company's business, financial condition, results of operations and prospects.

The Company's facilities, operations and activities emit greenhouse gases, which will likely subject the Company to possible future legislation regarding the regulation of emissions of greenhouse gases.

Announcements from the federal and provincial governments on regulations for greenhouse gas and air emissions legislation have caused uncertainty and changed the environmental regulation of natural resource development. The Company's exploration and production facilities and other operations and activities emit greenhouse gases. Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases. While the federal government has largely abandoned its intent to comply with its Kyoto Protocol obligations, the federal government has provided a draft framework for the federal regulation of greenhouse gases. As such, there is no federal legislative scheme in Canada for the regulation of greenhouse gases. Until that time, the impact of federal greenhouse gas regulation on the Company’s operations is unknown. These regulations may require the reduction of emissions produced by the Company's operations and facilities and the direct and indirect cost of compliance with the regulations may adversely affect the business, financial condition, results of operations and prospects of the Company.

In 2007, the Alberta government’s *Climate Change Emissions Management Act* and *Specified Gas Emitters Regulation* came into effect and require that facilities emitting more than 100,000 tonnes of greenhouse gases reduce their greenhouse gas emission intensity by 12 percent over their average intensity levels of 2003, 2004 and 2005. If the emissions intensity target is not met through improvements in operations, compliance tools include: per tonne payment into the climate change emissions management fund; purchase of Alberta-based offsets or purchase of emission performance credits from a different Alberta facility. Failure to comply with these regulations may result in a penalty of $200 per tonne of greenhouse gases over the allowable greenhouse gas emission intensity limit.

As a public company, the Company’s compliance costs and risks have increased in recent years.

Legal, accounting and other expenses associated with public company reporting requirements have increased significantly in the past few years. The Company anticipates that general and administrative costs associated with regulatory compliance will continue to increase with on-going compliance requirements under the Sarbanes-Oxley Act of 2002, as well as any new rules implemented by the SEC, Canadian Securities Administrators, the NYSE Amex Equities and the Toronto Stock Exchange in the future. These rules and regulations have significantly increased the Company’s legal and financial compliance costs and made some activities more time-consuming and costly. The Company cannot assure you that it will continue to effectively meet all of the requirements of these regulations, including Section 404 of the Sarbanes-Oxley Act and National Instrument 52-109 of the Canadian Securities Administrators. Any failure to effectively implement internal controls, or to resolve difficulties encountered in their implementation, could harm the Company’s operating results, cause the Company to fail to meet reporting obligations, or result in the Company’s principal executive officer and principal financial officer being required to give a qualified assessment of the internal control over financial reporting or the Company’s independent auditors providing an adverse opinion regarding the Company’s principal executive officer and principal financial officer’s assessment of the internal control over financial reporting. Any such result could cause investors to lose confidence in the Company’s reported financial information, which could have a material adverse effect on the trading price of the Company’s common shares and its ability to raise capital. These rules and regulations have made it more difficult and more expensive for the Company to obtain director and officer liability insurance, and the Company may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage in the future. As a result, it may be more difficult for the Company to attract and retain qualified individuals to serve on its board of directors or as executive officers.

Risks related to investing in the Company

The Company has not paid any dividends on our common shares. Consequently, an investor’s only opportunity currently to achieve a return on its investment will be if the market price of the Company’s common stock appreciates above the price that the investor paid for it.

The Company has not declared or paid any dividends on its common shares since the Company’s incorporation. Any decision to pay dividends on the shares of the Company will be made by its board of directors on the basis of the Company's earnings, financial requirements and other conditions existing at such future time. See "*Dividend Policy*." Consequently, an investor’s only opportunity to achieve a return on its investment in the Company will be if the market price of the Company’s common stock appreciates and the investor is able to sell its shares at a profit.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The reports on reserves data in Form 51-101F2 and the report of management and the directors on oil and gas disclosure in Form 51-101F3 are attached as Schedules "A" and "B", respectively, to this AIF, which forms are incorporated herein by reference.

Disclosure of Reserves Data

All of the Company's reserves herein reported were evaluated by independent evaluators in accordance with NI 51-101. AJM Deloitte, independent petroleum engineering consultants based in Calgary, Alberta were retained by the Company to evaluate the Canadian properties of the Company. Their report, titled "Reserve and Resource Estimation and Economic Evaluation, Dejour Energy (Alberta) Ltd.", is dated January 30, 2013 and has an effective date of December 31, 2012.

Gustavson Associates, an independent petroleum engineering consultants based in Denver, Colorado were retained by the Company to evaluate the US properties of the Company. Their report, titled "Reserve Evaluation Report, Dejour Energy (USA) Corp., Leasehold Garfield County, Colorado, USA" is dated March 12, 2013 and has an effective date of January 1, 2013.

The reserves data set forth below (the "**Reserves Data**"), derived from AJM and Gustavson's reports, summarizes the oil, liquids and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs as at December 31, 2012. The Net Present Value at 10% discount rate (before tax) ("**NPV_{10}**") for the Company's total proved and probable reserves was $99 million.

The AJM and Gustavson reports are based on certain factual data supplied by the Company and AJM and Gustavson's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Company's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Company to AJM and Gustavson and accepted without any further investigation. AJM and Gustavson accepted this data as presented and neither title searches nor field inspections were conducted. All statements relating to the activities of the Company for the year ended December 31, 2012 include a full year of operating data on the properties of the Company.

The Company reports in Canadian currency and therefore the Reserves Data set forth in the tables below has been converted to Canadian dollars at the prevailing conversion rate at December 31, 2012. The conversion rate used per Bank of Canada is 0.9949.

Cautionary Statements

All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Company's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas liquids and natural gas reserves may be greater than or less than the estimates provided herein.

Reserves Data ***(Forecast Prices and Costs)***

Breakdown of Gross Reserves (Forecast Case)

As of January 1, 2013	Light and Medium Oil (Mbbl)			NATURAL GAS (MMcf)			NATURAL GAS LIQUIDS (Mbbl)			OIL EQUIVALENT (Mboe)		
	CAN	USA	Total	CAN	USA	Total	CAN	USA	Total	CAN	USA	Total
RESERVES CATEGORY												
PROVED												
Developed producing	299.1	-	299.1	620.4	171.0	791.4	1.7	16.0	17.7	404.1	44.5	448.6
Developed Non-Producing	-	-	-	74.6	180.0	254.6	2.6	18.0	20.6	15.0	48.0	63.0
Undeveloped	-	-	-	-	74,745.0	74,745.0	-	7,535.0	7,535.0	-	19,992.5	19,992.5
TOTAL PROVED	**299.1**	**-**	**299.1**	**695.0**	**75,096.0**	**75,791.0**	**4.3**	**7,569.0**	**7,573.3**	**419.1**	**20,085.0**	**20,504.1**
PROBABLE	65.8	-	65.8	338.5	103,862.0	104,200.5	1.4	10,474.0	10,475.4	123.6	27,784.3	27,907.9
TOTAL PROVED PLUS PROBABLE	**364.9**	**-**	**364.9**	**1,033.5**	**178,958.0**	**179,991.5**	**5.7**	**18,043.0**	**18,048.7**	**542.7**	**47,869.3**	**48,412.0**

Note: AJM and Gustavson were not commissioned to evaluate possible reserves in Canada and USA respectively; therefore no values are entered for “Possible” reserves in both Canada and USA.

Breakdown of Net Reserves (Forecast Case)

As of January 1, 2013	TOTAL OIL (Mbbl)			NATURAL GAS (MMcf)			NATURAL GAS LIQUIDS (Mbbl)			OIL EQUIVALENT (Mboe)		
	CAN	USA	Total	CAN	USA	Total	CAN	USA	Total	CAN	USA	Total
RESERVES CATEGORY												
PROVED												
Developed producing	261.3	-	261.3	437.1	120.0	557.1	1.2	11.0	12.2	335.4	31.0	366.4
Developed Non-Producing	-	-	-	60.2	124.0	184.2	1.6	13.0	14.6	11.6	33.7	45.3
Undeveloped	-	-	-	-	51,575.0	51,575.0	-	5,576.0	5,576.0	-	14,171.8	14,171.8
TOTAL PROVED	**261.3**	**-**	**261.3**	**497.3**	**51,819.0**	**52,316.3**	**2.8**	**5,600.0**	**5,602.8**	**347.0**	**14,236.5**	**14,583.5**
PROBABLE	58.4	-	58.4	235.4	71,468.0	71,703.4	0.9	7,748.0	7,748.9	98.6	19,659.3	19,757.9
TOTAL PROVED PLUS PROBABLE	**319.7**	**-**	**319.7**	**732.7**	**123,287.0**	**124,019.7**	**3.7**	**13,348.0**	**13,351.7**	**445.6**	**33,895.8**	**34,341.4**

Note: AJM and Gustavson were not commissioned to evaluate possible reserves in Canada and USA respectively; therefore, no values are entered for “Possible” reserves in both Canada and USA.

Net Present Value of Future Net Revenue (Forecast Case) - Before Income Taxes

As of December 31, 2012 **Total (in Thousands of CAD$)**		**M$** Discounted at 0%			**M$** Discounted at 5%			**M$** Discounted at 10%			**M$** Discounted at 15%			**M$** Discounted at 20%	
	CAN	USA	Total	CAN	USA	Total	CAN	USA	Total	CAN	USA	USA	CAN	USA	Total
PROVED															
Developed Producing	10,121.2	594.5	10,715.7	8,908.4	431.8	9,340.2	7,981.2	342.5	8,323.7	7,258.9	287.2	7,546.1	6,684.1	249.6	6,933.7
Developed Non-Producing	153.9	713.8	867.7	117.4	436.8	554.2	90.0	309.0	399.0	69.2	240.9	310.1	53.1	200.1	253.2
Undeveloped	-	221,258.8	221,258.8	-	96,719.4	96,719.4	-	46,953.1	46,953.1	-	22,699.9	22,699.9	-	9,352.0	9,352.0
TOTAL PROVED	**10,275.1**	**222,567.1**	**232,842.2**	**9,025.8**	**97,588.0**	**106,613.8**	**8,071.2**	**47,604.6**	**55,675.8**	**7,328.1**	**23,228.0**	**30,556.1**	**6,737.2**	**9,801.7**	**16,538.9**
PROBABLE	3,546.5	333,024.0	336,570.5	2,357.5	109,854.3	112,211.8	1,678.7	41,532.0	43,210.7	1,264.7	16,375.4	17,640.1	996.9	6,125.2	7,122.1
TOTAL PROVED PLUS PROBABLE	**13,821.6**	**555,591.1**	**569,412.7**	**11,383.3**	**207,442.3**	**218,825.6**	**9,749.9**	**89,136.6**	**98,886.5**	**8,592.8**	**39,603.4**	**48,196.2**	**7,734.1**	**15,926.9**	**23,661.0**

Note: All the above figures are in Canadian dollar, converted using December 31, 2012 exchange rate of US$1.00 = CAD$0.9949.

Net Present Value of Future Net Revenue (Forecast Case) – After Income Taxes

As of December 31, 2012 Total (in Thousands of CAD$)	M$ Discounted at 0%			M$ Discounted at 5%			M$ Discounted at 10%			M$ Discounted at 15%			M$ Discounted at 20%		
	CAN	USA	Total	CAN	USA	Total	CAN	USA	Total	CAN	USA	USA	CAN	USA	Total
PROVED															
Developed Producing	10,121.2	392.3	10,513.5	8,908.4	284.9	9,193.3	7,981.2	226.1	8,207.3	7,258.9	189.5	7,448.4	6,684.1	164.8	6,848.9
Developed Non-Producing	153.9	471.1	625.0	117.4	288.3	405.7	90.0	204.0	294.0	69.2	159.0	228.2	53.1	132.0	185.1
Undeveloped	-	153,590.4	153,590.4	-	67,708.2	67,708.2	-	32,583.1	32,583.1	-	15,145.8	15,145.8	-	5,431.4	5,431.4
TOTAL PROVED	**10,275.1**	**154,453.8**	**164,728.9**	**9,025.8**	**68,281.4**	**77,307.2**	**8,071.2**	**33,013.2**	**41,084.4**	**7,328.1**	**15,494.3**	**22,822.4**	**6,737.2**	**5,728.2**	**12,465.4**
PROBABLE	3,546.5	231,874.6	235,421.1	2,357.5	76,921.5	79,279.0	1,678.7	28,710.1	30,388.8	1,264.7	10,861.6	12,126.3	996.9	3,638.4	4,635.3
TOTAL PROVED PLUS PROBABLE	**13,821.6**	**386,328.4**	**400,150.0**	**11,383.3**	**145,202.9**	**156,586.2**	**9,749.9**	**61,723.3**	**71,473.2**	**8,592.8**	**26,355.9**	**34,948.7**	**7,734.1**	**9,366.6**	**17,100.7**

Note: All figures in Canadian dollar, converted using December 31, 2012 exchange rate of US$1.00 = CAD$0.9949.

Net Present Value of Future Net Revenue (Forecast Case) – Before Income Taxes

Consolidated As of December 31, 2012
(in Canadian dollars)

	M$ CAN	M$ USA	M$ Total	$/boe CAN	$/boe USA	$/Mcfe CAN	$/Mcfe USA
	(in thousands of Canadian dollars)			Discounted at 10% per year			
PROVED							
Developed Producing	7,981.2	342.5	8,323.7	23.80	-	3.97	1.85
Developed Non-Producing	90.0	309.0	399.0	7.70	-	1.28	1.51
Undeveloped	-	46,953.1	46,953.1	-	-	-	0.56
TOTAL PROVED	**8,071.20**	**47,604.6**	**55,675.8**	**23.26**	**-**	**3.88**	**0.56**
TOTAL PROBABLE	1,678.70	41,532.0	43,210.7	17.03	-	2.84	0.36
TOTAL PROVED PLUS PROBABLE	**9,749.90**	**89,136.6**	**98,886.5**	**21.88**	**-**	**3.65**	**0.44**

Note: All figures in Canadian dollar, converted using December 31, 2012 exchange rate of US$1.00 = CAD$0.9949.

Net Present Value of Future Net Revenue (Forecast Case) by Production Group – Before Income Taxes

Canada
As at December 31, 2012
(in Canadian dollars)

	Discounted at 10% per year M$	$/boe	$/Mcfe
PROVED PRODUCING			
Light & Medium Oil [1]	7,980.70	29.79	4.97
Natural Gas [2]	0.40	0.01	0.00
TOTAL: PROVED PRODUCING	**7,981.10**	**23.80**	**3.97**
TOTAL PROVED			
Light & Medium Oil [1]	7,980.70	29.79	4.97
Natural Gas [2]	90.50	1.14	0.19
TOTAL: TOTAL PROVED	**8,071.20**	**23.26**	**3.88**
TOTAL PROVED PLUS PROBABLE			
Light & Medium Oil [1]	9,378.40	28.61	4.77
Natural Gas [2]	371.50	3.15	0.53
TOTAL: TOTAL PROVED PLUS PROBABLE	**9,749.90**	**21.88**	**3.65**

[1] Including solution gas and other by-products

[2] Including by-products but excluding solution gas

[3] Unit values are based on Company Net Reserve

Net Present Value of Future Net Revenue (Forecast Case) by Production Group – Before Income Taxes

USA
As at December 31, 2012
(in Canadian dollars)

	Discounted at 10% per year		
	M$	**$/boe**	**$/Mcfe**
PROVED PRODUCING			
Light & Medium Oil	0.00	0.00	0.00
Natural Gas	342.50	11.00	1.83
TOTAL: PROVED PRODUCING	**342.50**	**11.00**	**1.83**
TOTAL PROVED			
Light & Medium Oil	0.00	0.00	0.00
Natural Gas	47,604.70	3.30	0.55
TOTAL: TOTAL PROVED	**47,604.70**	**3.30**	**0.55**
TOTAL PROVED PLUS PROBABLE			
Light & Medium Oil	0.00	0.00	0.00
Natural Gas	89,136.60	2.60	0.43
TOTAL: TOTAL PROVED PLUS PROBABLE	**89,136.60**	**2.60**	**0.43**

[1] Unit values are based on Company Net Reserve

Additional Information Concerning Future Net Revenue (Forecast Case) (Undiscounted)

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Capital Development Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Tax (M$)	Future Net Revenue After Income Taxes (M$)
Canada								
PROVED								
Developed Producing	27,319.7	3,661.7	12,907.1	-	629.8	10,121.2	-	10,121.2
Developed Non-Producing	534.1	66.3	160.8	153.0	-	153.9	-	153.9
Undeveloped	-	-	-	-	-	-	-	-
TOTAL PROVED	**27,853.8**	**3,728.0**	**13,067.9**	**153.0**	**629.8**	**10,275.1**	**-**	**10,275.1**
PROBABLE	**7,909.4**	**1,114.5**	**3,238.8**	**-**	**9.6**	**3,546.5**	**-**	**3,546.5**
TOTAL PROVED PLUS PROBABLE	**35,763.2**	**4,842.5**	**16,306.7**	**153.0**	**639.4**	**13,821.6**	**-**	**13,821.6**

Note: All figures in Canadian dollar, converted using December 31, 2012 exchange rate of US$1.00 = CAD$0.9949.

<u>Additional Information Concerning Future Net Revenue (Forecast Case) (Undiscounted)</u>

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Tax (M$)	Future Net Revenue After Income Taxes (M$)
USA								
PROVED								
Developed Producing	1,105.6	206.0	300.3	-	5.0	594.5	202.1	392.3
Developed Non-Producing	1,486.7	297.2	472.2	-	3.5	713.8	242.7	471.1
Undeveloped	624,672.2	124,692.3	151,970.7	125,898.7	851.6	221,258.8	67,668.5	153,590.4
TOTAL PROVED	**627,264.6**	**125,195.5**	**152,743.1**	**125,898.7**	**860.1**	**222,567.1**	**68,113.2**	**154,453.7**
PROBABLE	940,565.1	187,994.2	217,091.6	201,310.7	1,144.6	333,024.0	101,149.5	231,874.6
TOTAL PROVED PLUS PROBABLE	**1,567,829.7**	**313,189.7**	**369,834.7**	**327,209.4**	**2,004.7**	**555,591.1**	**169,262.7**	**386,328.3**

Note: All figures in Canadian dollar, converted using December 31, 2012 exchange rate of US$1.00 = CAD$0.9949.

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Capital Development Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Tax (M$)	Future Net Revenue After Income Taxes (M$)
Total								
PROVED								
Developed Producing	28,425.3	3,867.7	13,207.4	-	634.8	10,715.7	202.1	10,513.5
Developed Non-Producing	2,020.8	363.5	633.0	153.0	3.5	867.7	242.7	625.0
Undeveloped	624,672.2	124,692.3	151,970.7	125,898.7	851.6	221,258.8	67,668.5	153,590.4
	-	-	-	-	-	-	-	-
TOTAL PROVED	**655,118.4**	**128,923.5**	**165,811.0**	**126,051.7**	**1,489.9**	**232,842.2**	**68,113.2**	**164,728.8**
	-	-	-	-	-	-	-	-
PROBABLE	948,474.5	189,108.7	220,330.4	201,310.7	1,154.2	336,570.5	101,149.5	235,421.1
	-	-	-	-	-	-	-	-
TOTAL PROVED PLUS PROBABLE	**1,603,592.9**	**318,032.2**	**386,141.4**	**327,362.4**	**2,644.1**	**569,412.7**	**169,262.7**	**400,149.9**

Note: All figures in Canadian dollar, converted using December 31, 2012 exchange rate of US$1.00 = CAD$0.9949.

Pricing Assumptions

Canada

The benchmark reference pricing as at December 31, 2012 used for the Reserves Data respecting Canadian properties was provided by AJM Deloitte, a qualified reserves evaluator and independent of the Company, and is set forth below:

Crude Oil and Natural Gas Liquids Price Forecast

			NYMEX WTI at Cushing Oklahoma		Edmonton City Gate		Med. Oil 29 Deg. API Cromer, SK	Bow River 25 Deg. API Hardisty	Heavy Oil 12 Deg. API Hardisty	Alberta Natural Gas Liquids (Edmonton Par Prices)			
Year	Inflation %	Exchange Rate $US/ $Cdn	Real $US/bbl	Current $US/bbl	Real $Cdn/bbl	Current $Cdn/bbl	Current $Cdn/bbl	Current $Cdn/bbl	Current $Cdn/bbl	Ethane $Cdn/bbl	Propane $Cdn/bbl	Butane $Cdn/bbl	Pentanes + Condensate $Cdn/bbl
2013	0.0	1.000	90.00	90.00	85.00	85.00	78.75	67.00	61.00	8.70	46.75	72.25	89.25
2014	2.0	1.000	88.00	89.75	83.00	84.70	77.80	66.70	60.70	10.35	46.60	72.00	88.95
2015	2.0	1.000	88.00	91.55	85.95	89.45	81.65	70.45	64.45	11.25	49.20	76.05	93.90
2016	2.0	1.000	88.00	93.40	85.95	91.20	82.40	71.20	65.20	12.15	50.15	77.50	95.75
2017	2.0	1.000	85.00	92.00	82.95	89.80	80.70	70.80	64.80	13.05	49.40	76.35	94.30
2018	2.0	1.000	85.00	93.85	82.95	91.60	81.45	71.60	65.60	14.40	50.40	77.85	96.20
2019	2.0	1.000	85.00	95.70	82.95	93.40	82.60	73.40	67.40	15.30	51.35	79.40	98.05
2020	2.0	1.000	85.00	97.65	82.95	95.30	82.70	74.30	68.30	16.35	52.40	81.00	100.05
2021	2.0	1.000	85.00	99.60	82.95	97.20	83.20	76.20	70.20	17.40	53.45	82.60	102.05
2022	2.0	1.000	85.00	101.60	82.95	99.15	85.15	78.15	72.15	18.45	54.55	84.30	104.10
2023	2.0	1.000	85.00	103.60	82.95	101.10	86.10	79.10	73.10	19.95	55.60	85.95	106.15
2024	2.0	1.000	85.00	105.70	82.95	103.15	88.15	81.15	75.15	20.40	56.75	87.70	108.30
2025	2.0	1.000	85.00	107.80	82.95	105.20	90.20	83.20	77.20	20.85	57.85	89.40	110.45
2026	2.0	1.000	85.00	109.95	82.95	107.30	92.30	85.30	79.30	21.15	59.00	91.20	112.65
2027	2.0	1.000	85.00	112.15	82.95	109.45	94.45	87.45	81.45	21.60	60.20	93.05	114.90
2028	2.0	1.000	85.00	114.40	82.95	111.65	96.65	89.65	83.65	22.05	61.40	94.90	117.25
2029	2.0	1.000	85.00	116.70	82.95	113.85	98.85	91.85	85.85	22.50	62.60	96.75	119.55
2030	2.0	1.000	85.00	119.00	82.95	116.15	101.15	94.15	88.15	23.10	63.90	98.75	121.95
2031	2.0	1.000	85.00	121.40	82.95	118.45	103.45	96.45	90.45	23.55	65.15	100.70	124.35
2032	2.0	1.000	85.00	123.85	82.95	120.85	105.85	98.85	92.85	24.00	66.45	102.70	126.90
2032+	2.0	1.000	+0%/yr	+2%/yr	+0%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	Escalate at 2% per year			

Natural Gas and Sulfur Price Forecast

Natural Gas pricing										Sulphur
	Alberta Reference Average Price	Alberta AECO Average Price		Alberta System Plant Gate Sales	Alberta Direct Plant Gate Sales	B.C. Direct Stn. 2 Sales	Sask. Direct Plant Gate Sales	NYMEX		Alberta Plant Gate
Year	Current $Cdn/mcf	Real $Cdn/mcf	Current $Cdn/mcf	Current $Cdn/mcf	Current $Cdn/mcf	Current $Cdn/mcf	Current $Cdn/mcf	Real $US/mcf	Current $US/mcf	Current $Cdn/lt
2013	2.95	3.20	3.20	2.90	3.00	2.90	3.15	3.50	3.50	80.00
2014	3.50	3.70	3.75	3.45	3.55	3.45	3.70	4.00	4.10	81.60
2015	3.80	3.90	4.05	3.75	3.85	3.75	4.00	4.20	4.35	83.25
2016	4.10	4.10	4.35	4.05	4.15	4.05	4.30	4.40	4.65	84.90
2017	4.40	4.30	4.65	4.35	4.45	4.35	4.60	4.60	5.00	86.60
2018	4.85	4.60	5.10	4.80	4.90	4.80	5.05	4.90	5.40	88.35
2019	5.15	4.80	5.40	5.10	5.20	5.10	5.35	5.10	5.75	90.10
2020	5.50	5.00	5.75	5.45	5.55	5.45	5.70	5.30	6.10	91.90
2021	5.85	5.20	6.10	5.80	5.90	5.80	6.05	5.50	6.45	93.75
2022	6.20	5.40	6.45	6.15	6.25	6.15	6.40	5.70	6.80	95.65
2023	6.70	5.70	6.95	6.65	6.75	6.65	6.90	6.00	7.30	97.55
2024	6.85	5.70	7.10	6.80	6.90	6.80	7.05	6.00	7.45	99.50
2025	7.00	5.70	7.25	6.95	7.05	6.95	7.20	6.00	7.60	101.50
2026	7.10	5.70	7.35	7.05	7.15	7.05	7.30	6.00	7.75	103.55
2027	7.25	5.70	7.50	7.20	7.30	7.20	7.45	6.00	7.90	105.60
2028	7.40	5.70	7.65	7.35	7.45	7.35	7.60	6.00	8.10	107.70
2029	7.55	5.70	7.80	7.50	7.60	7.50	7.75	6.00	8.25	109.85
2030	7.75	5.70	8.00	7.70	7.80	7.70	7.95	6.00	8.40	112.05
2031	7.90	5.70	8.15	7.85	7.95	7.85	8.10	6.00	8.55	114.30
2032	8.05	5.70	8.30	8.00	8.10	8.00	8.25	6.00	8.75	116.60
2032+	+2%/yr	+0%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+0%/yr	+2%/yr	+2%/yr

Pricing assumptions

USA

The benchmark reference pricing as at December 31, 2012 used for the Reserves Data respecting U.S. properties was provided by Gustavson, a qualified reserves evaluator and independent of the Company, and is set forth below:

Crude Oil and Natural Gas Liquids Price Forecast

	Crude Oil			Natural Gas Liquids			
Year	Proved Developed $US/bbl	Proved Undeveloped $US/bbl	Probable Undeveloped $US/bbl	Proved Developed Producing $US/bbl	Proved Developed Non-Producing $US/bbl	Proved Undeveloped $US/bbl	Probable Undeveloped $US/bbl
2013	85.05	85.05	-	49.67	57.55	57.06	-
2014	84.87	84.87	-	53.52	60.52	60.30	-
2015	82.96	82.96	-	56.09	62.09	61.88	-
2016	81.20	81.20	-	54.81	60.68	60.53	-
2017	79.99	79.99	-	53.93	59.72	59.62	-
2018	80.90	80.90	-	54.59	60.44	60.37	-
2019+	81.84	81.84	81.84	55.27	61.20	61.13	61.20

Natural Gas and Sulphur Price Forecast

Year	Proved Developed $US/Mcf	Proved Undeveloped $US/Mcf	Probable Undeveloped $US/Mcf
2013	2.33	2.33	-
2014	2.81	2.81	-
2015	3.02	3.02	-
2016	3.21	3.21	-
2017	3.46	3.46	-
2018	3.64	3.64	-
2019	3.75	3.75	3.75
2020	4.00	4.00	4.00
2021	4.26	4.26	4.26
2022	4.52	4.52	4.52
2023	4.82	4.82	4.82
2024	5.11	5.11	5.11
2025+	5.46	5.46	5.46

Reconciliations of Changes in Reserves

A reconciliation of changes to the Company's gross proved, gross probable and gross proved plus probable reserves is provided below. This reconciliation reflects changes to the Company's reserves estimated using forecast prices and costs.

<u>Canada</u>

December 31, 2012
Reconciliation of Company Gross Reserves
by Principal Product Type, Canada

	Total Oil			Light and Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)
December 31, 2011	408.0	240.0	648.0	408.0	240.0	648.0	0	0	0	5.3	1.5	6.8
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	0	0	0	0	0	0	0	0	0	0	0	0
Infill Drilling*	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	(39.3)	(174.2)	(213.5)	(39.3)	(174.2)	(213.5)	0	0	0	(0.1)	(0.1)	(0.2)
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	(69.6)	0	(69.6)	(69.6)	0	(69.6)	0	0	0	(0.9)	0	(0.9)
December 31, 2012	299.1	65.8	364.9	299.1	65.8	364.9	0	0	0	4.3	1.4	5.7

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	+ Proved Probable (Mboe)
December 31, 2011	1,097.4	405.8	1,503.2	1,097.4	405.8	1,503.2	0	0	0	596.2	309.2	905.4
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	0	0	0	0	0	0	0	0	0	0	0	0
Infill Drilling*	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	(13.8)	(67.3)	(81.1)	(13.8)	(67.3)	(81.1)	0	0	0	(41.8)	(185.6)	(227.4)
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	(388.7)	0	(388.7)	(388.7)	0	(388.7)	0	0	0	(135.3)	0	(135.3)
December 31, 2012	694.9	338.5	1,033.4	694.9	338.5	1,033.4	0	0	0	419.1	123.6	542.7

*The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook

USA

January 1, 2013

Reconciliation of Company Gross Reserves by Principal Product Type, USA

	Total Oil			Total Natural Gas Liquids			Condensate			Natural Gas Liquids		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	+ Proved Probable (Mbbl)	Proved (Mbbl)	Probabl e (Mbbl)	+ Proved Probable (Mbbl)
January 1, 2012	0	0	0	6,719	8,943	15,662	464	632	1,096	6,255	8,311	14,566
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	0	0	0	0	0	0	0	0	0	0	0	0
Infill Drilling*	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	0	0	0	850	1,531	2,381	64	111	175	786	1,420	2,206
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	0	0	0	0	0	0	0	0	0	0	0	0
Production	0	0	0	0	0	0	0	0	0	0	0	0
January 1, 2013	0	0	0	7,569	10,474	18,043	528	743	1,271	7,041	9,731	16,772

	Total Gas			Conventional Natural Gas			Coal Bed Methane			BOE		
FACTORS	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	+ Proved Probable (MMcf)	Proved (Mboe)	Probabl e (Mboe)	+ Proved Probable (Mboe)
January 1, 2012	66,937	88,719	155,656	66,937	88,719	155,656	0	0	0	17,875	23,731	41,606
Discoveries	0	0	0	0	0	0	0	0	0	0	0	0
Extensions*	0	0	0	0	0	0	0	0	0	0	0	0
Infill Drilling*	0	0	0	0	0	0	0	0	0	0	0	0
Improved Recovery*	0	0	0	0	0	0	0	0	0	0	0	0
Technical Revisions	8,168	15,143	23,311	8,168	15,143	23,311	0	0	0	2,212	4,053	6,265
Acquisitions	0	0	0	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0	0	0	0
Economic Factors	(10)	0	(10)	(10)	0	(10)	0	0	0	(3)	0	(3)
Production	0	0	0	0	0	0	0	0	0	0	0	0
January 1, 2013	75,095	103,862	178,957	75,095	103,862	178,957	0	0	0	20,084	27,784	47,868

*The above change categories correspond to standards set out in the Canadian Oil and Gas Evaluation Handbook.

Additional Information Relating to Reserves Data

Undeveloped Gross Reserves (Canada)

		Company Gross Reserves First Attributed By Year					
Product Type	**Units**	**Prior**	**2008**	**2009**	**2010**	**2011**	**2012**
Proved Undeveloped							
Light and Medium Oil	Mbbl	-	150	39	121	-	-
Natural Gas	MMcf	-	67	19	(16)	-	-
Total: Oil Equivalent	Mboe	-	161	42	119	-	-
Probable Undeveloped							
Light and Medium Oil	Mbbl	-	336	69	136	240	66
Natural Gas	MMcf	-	151	115	49	406	339
Natural Gas Liquids	Mbbl	-	1	-	-	2	1
Total: Oil Equivalent	Mboe	-	362	88	145	309	124

The above figures represent the total Company's gross reserves first attributed at year-end.
The significant majority of the undeveloped reserves are scheduled to be developed within the next three years.

Undeveloped Gross Reserves (USA)

		Company Gross Reserves First Attributed By Year				
Product Type	**Units**	**Prior**	**2009[(1)]**	**2010[(1)]**	**2011**	**2012**
Proved Undeveloped						
Light and Medium Oil	Mbbl	-	-	-	-	-
Natural Gas	MMcf	-	109,342	77,456	66,609	74,745
Natural Gas Liquids	Mbbl	-	721	558	6,691	7,535
Natural Gas Equivalent	Mboe	-	18,945	13,467	17,792	19,993
Probable Undeveloped						
Light and Medium Oil	Mbbl	-	-	-	-	-
Natural Gas	MMcf	-	149,316	105,773	88,719	103,862
Natural Gas Liquids	Mbbl	-	986	762	8,943	10,474
Natural Gas Equivalent	Mboe	-	25,872	18,391	23,731	27,784

(1) Reserve category "Light and Medium Oil" have been reclassified as "Natural Gas Liquids" for the years ended December 31, 2010 and 2009 to conform to the current year's AIF presentation.

According to Gustavson Associates, in Kokopelli Field Area, Dejour expects to continue its drilling program with 8 wells drilled in the 4th quarter of 2013 followed by the drilling of 16 wells per year in 2014 through 2027. In South Rangely Field Area, Dejour expects to continue its drilling program with 1 well drilled in 2013 followed by the drilling of 2 wells per year in 2014 and 2015.

Significant Factors or Uncertainties

The evaluated oil and gas properties of the Company have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company. Estimates of economically recoverable oil and natural gas reserves (including natural gas liquids) and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as availability of capital to fund required infrastructure, commodity prices, production performance of wells and well recompletion success rates, successful drilling of infill wells, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from actual results. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected there from, may vary. The Company's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material. In addition to the foregoing, other significant factors or uncertainties that may affect either the Company’s reserves or the future net revenue associated with such reserves include material changes to existing taxation or royalty rates and/or regulations, changes to environmental laws and regulations.

Information on other important economic factors or significant uncertainties that may affect components of the Reserves Data and other oil and gas information contained in this AIF are contained in the Company's Management Discussion and Analysis filed under the Company's profile at www.SEDAR.com.

Future Development Costs

A summary of the estimated development costs deducted in the estimation of future net revenue attributable to various reserves categories and prepared under various price and cost assumptions is provided in the following table. The Company expects to fund its estimated future development costs through a combination of internally generated cash flow, equity and debt financing. There can be no guarantee that funds will be available or that the Board of Directors of the Company will allocate funding to develop all of the reserves requiring development in the AJM and Gustavson reports. Failure to develop such reserves could negatively impact future net revenue.

Canada

Year	Development Costs (Forecast Prices and Costs) (in thousands of Canadian dollars) Total Proved	Total Proved Plus Probable
2013	-	-
2014	153	153
2015	-	-
2016	-	-
2017 onward	-	-
Total	153	153

USA

Year	Development Costs (Forecast Prices and Costs) (in thousands of Canadian dollars) Total Proved	Total Proved Plus Probable
2013	10,956	10,956
2014	22,349	22,349
2015	22,796	22,796
2016	22,323	22,323
2017	22,769	22,769
2018	23,225	23,225
2019	1,480	23,689
2020 onward	852	181,099
Total	126,750	329,205

Note: The above figures in both Canada and USA are undiscounted figures.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

US Oil and Gas Interests

Kokopelli, Piceance Basin

During 2012, the Company drilled an initial well into the Willams Fork liquids-rich natural gas formation at Kokopelli to hold its 2,200 acres of leasehold interests. The Company also entered into a financial contract with an industry Drilling Fund to complete and tie-in the initial well and drill, complete, and tie-in an additional 3 wells. The Drilling Fund's investment of US$6,500,000 represents about 80% of the total program cost of US$8,200,000. The primary producing geological horizons are the Williams Fork and Mancos zones at depths ranging from 9,000 to 10,500 ft. respectively.

The Company's 4-well drilling and completion program at Kokopelli will focus strictly on the Williams Fork formation and is expected to be completed by June 30, 2013.

Dejour has a 72% working interest in this 2,200 acre Kokopelli project. To date, the Company has delineated 92 proved undeveloped ("PUD") drilling locations on 10-acre spacing in the Williams Fork. As at December 31, 2012, the total proved and probable reserves, net to the Company's working interest are 33.6 million BOE having a NPV before tax, discounted at 10% of US$88.9 million. WPX Energy, Rocky Mountain LLC, Inc. and Bill Barrett Corporation are developing and producing the Williams Fork on adjacent acreage to the east, west and north of the Company's acreage. Dejour has worked closely with important constituents including local citizenry and the Bureau of Land Management ("BLM") in the US and the Colorado Division of Wildlife ("Dept. of Wildlife") to develop a mutually acceptable development plan for this environmentally sensitive area. This hard work has resulted in the issuance of the applicable drilling permits to our Company by the BLM and Dept. of Wildlife.

Following completion of the 4-well drilling program, the Company will base its future development plans for Kokopelli on an assessment of a) the NYMEX futures market for natural gas b) the natural gas liquids markets at the Mt. Belvieu, Texas and Conway, Kansas sales points, and c) the production results from the initial wells. Given acceptable prices and production results, and subject to available financing, the Company will drill 8 other Williams Fork wells at Kokopelli in 2013 and an additional 16 wells in 2014.

South Rangely, Piceance Basin

The Company has 1 producing well on the South Rangely block, north of Kokopelli. The block consists of 5,500 gross acres (4,490 net acres). The "South Rangely 36-24A" well was drilled by the Company in June 2011 and commenced production in late December 2011. Casing was set on approximately 90 ft. of Mancos "B" Sand and later fractured and stimulated. The well flowed rich gas from the Mancos "B" Sand in commercial quantities. The well is currently producing about 400 mcf/d of liquids-rich natural gas. The Company's independent reservoir engineers have assigned reserves of 261, 000 BOE to the "South Rangely 36-24A" well having a NPV before tax, discounted at 10% of US$344,000 as at December 31, 2012.

West Grand Valley, Piceance Basin – Evolution of the Niobrara/Mancos Shale Resource Play

In August 2012, a major US exploration and production company drilled a Niobrara/Mancos shale discovery well at a vertical depth of about 10,200 ft. with a horizontal (HZ) leg of about 4,600 ft. mid-way between our Grand Valley (Roan Creek) and Kokopelli leaseholds. The well recovered 535 ft. of continuous core and was completed with a 17-stage stimulation. The well tested at 16 million cubic feet of natural gas per day. Choked back, the well is producing at a rate of about 12 million cubic feet per day.

Dejour has approximately 12,000 gross acres (9,000 net acres) with “Niobrara/Mancos Shale” potential in Garfield County, Colorado.

Consulting geologists have determined our acreage is highly prospective for the Niobrara/Mancos shale in Garfield County. While drilling costs are higher in the Niobrara/Mancos, due to the greater vertical depth and the requirement for a HZ leg, the production and reserve potential of the Niobrara/Mancos far outweigh the incremental costs to develop the formation. Interest in the Company’s Garfield County acreage has intensified since the discovery well drilled to the Niobrara/Mancos formation by our competitor. We look forward to refining our understanding of the Niobrara/Mancos reserve potential of our acreage and establishing a go-forward capital expenditure program that is focused on development using multi-well pads on this exciting liquids-rich shale play.

On November 5, 2012, the Company entered into a “Lease Purchase and Farmout Agreement” (“the Agreement”) with the major US exploration and production company who drilled the discovery Niobrara/ Mancos shale well, in Paragraph 1, above, with respect to our West Grand Valley acreage. Approximately 2,300 acres were sold for cash while the remaining 5,200 acres were farmed out under the following terms and conditions:

a) The major US company will drill three (3) separate Test Wells on the three (3) lease tracts comprising the 5,200 acres and earn a 100% working interest before payout after which Dejour will earn the right to back-in for a 20% working interest on a well-by-well basis;

b) The wells must be drilled prior to the end of the expiration date of each lease which range from June 30, 2014 to September 30, 2014, and

c) Future development of the separate tracts, if any, will be based upon the after-payout working interest earned by each party to the Agreement.

Other Exploration Acreage – Piceance Basin

As at December 31, 2012, Dejour holds approximately 168,000 gross acres (118,000 net acres) in undeveloped lands, most of which are in the Piceance Basin. Based on a 2009 geological study, the Company has identified the following two (2) projects to further explore as expected cash flows from our Kokopelli, South Rangely, and West Grand Valley projects develop:

a) Plateau – This 3,014 acre project is located south of West Grand Valley/Roan Creek and has significant Williams Fork potential as evidenced by successful drilling on an adjacent block;

b) North Rangely – This 19,821 acre block is prospective for oil in the Niobrara/Lower Mancos shale, Dakota, Morrison and Phosphoria formations.

Canadian Oil and Gas Interests

Drake/Woodrush, Ft. St. John, British Columbia

The Company's Drake/Woodrush oilfield is located about 110 km. north of Ft. St. John, British Columbia, Canada. In early 2011, the Company implemented a waterflood in the Halfway geological formation. In October 2011, Dejour received regulatory approval to operate the waterflood on a voidage replacement basis and, in December, 2011, the Company drilled a 3rd oil production well while increasing water injection from 1,200 BOWD to 2,400 BOWD.

The Company presently owns a 75% working interest at Drake/Woodrush in 3 producing oil wells and 4 producing natural gas wells. Gross production from the pool has averaged 565 BOE/d (425 net) during the month of March 2013. This represents a production increase of about 75% over average daily production from the field in Q4 2012. Part of this increase is due to the increasing bottom-hole pressure in the producing oil wells while part is due to the temporary shut-in of a key producing well in Q4 2012.

As at December 31, 2012, the Company's independent reservoir engineers assigned proved and probable reserves of 525,000 BOE to the Company's working interest at Drake/Woodrush having a NPV before tax, discounted at 10% of $9.9 million.

Presently, the Company is reviewing operations in an effort to reduce operating costs, increase operating efficiencies (gas transmission contracts, compressor costs, etc.) and increase netbacks. Subject to the continued positive performance of the waterflood, the Company plans a geological review of its 8,500 acres at Drake/Woodrush in Q3 2013 to define additional drilling targets, if any, for further development should regional commodity prices improve over current levels.

Exploration, Development and Producing Activities

	Non-Producing Exploratory and Development Wells		Producing Wells	
Canada	**Gross**	**Net**	**Gross**	**Net**
Oil	-	-	3	2.25
Gas	-	-	5	3.69
Service Wells	2	1.50	3	2.25
Dry Holes	4	2.80	-	-
Suspended	2	0.60	1	0.69
	8	4.90	12	8.88
United States	1	0.10	1	0.40
TOTAL	9	5.00	13	9.28

All the above wells are located in Canada and USA.

The Company's significant exploration and development activities are described under "*Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties and Wells*".

Properties with no Attributed Reserves

As at December 31, 2012, the Company owned approximately 4,780 gross acres (approximately 1,024 net acres) of properties in Canada with no attributed reserves. As at December 31, 2012, the Company had approximately 117,000 net acres of properties in the US that have no attributed reserves. As at the date of this AIF, there is currently no work commitments related to the Company's properties with no attributed reserves.

Forward Contracts

The Company is not bound by an agreement (including any transportation agreement) directly or through an aggregator, under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil and gas.

Additional Information Concerning Abandonment and Reclamation Costs

For the Company's Canadian and US oil and gas interests, the well abandonment costs for all wells with reserves have been included at the property level. The Company estimated the total undiscounted amount of the cash flows required to settle the retirement obligations as at December 31, 2012 to be approximately $1,928,000. These obligations are expected to be settled over the next 20 years with the majority of costs incurred between 2016 and 2030. Additional abandonment costs associated with non-reserves wells, lease reclamation costs and facility abandonment and reclamation expenses have not been included.

Tax Horizon

As at December 31, 2012, on a consolidated basis, the Company had approximately $38,086,000 of non-capital losses which can be applied to reduce future taxable income. In addition, the Company had consolidated exploration and development expenditures totaling approximately $50,505,000, unamortized share issue costs of approximately $988,000 and capital loss carry forwards of approximately $8,242,000 which may be available to reduce future taxable income. The exploration and development expenditures can be carried forward indefinitely. Therefore, management does not expect the Company to pay any income taxes until 2014 or later in both Canada and USA.

Costs Incurred

A summary of acquisition costs and exploration and development expenditures incurred in the Company's oil and gas properties for the year ended December 31, 2012 is as follows:

	Canada $	United States (1) $	Total $
Property acquisition costs			
Proved	13,629	39,579	53,208
Unproved	605	211,382	211,987
Exploration costs	132,400	103,547	235,947
Development costs	1,406,655	2,568,277	3,974,932
Total Costs Incurred	1,553,289	2,922,785	4,476,074

(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 Company's MD&A for the year ended December 31, 2012 for details)

Production Estimates

As at December 31, 2012, all of the Company's production is in Canada and specifically, British Columbia. In January 2013, one of the Company's US properties in the state of Colorado started producing. The following table sets forth estimated daily volumes of production for the 12 months of 2013 as reflected in the estimates of gross proved reserves and gross probable reserves provided in the table under the heading "Breakdown of Gross Reserves (Forecast Case)".

Canada	**Estimated 2013 Average Daily Production based on Forecast Prices**			
	Light and Medium Oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	Total Oil Equivalent (boe/d)
Proved	226	598	2	327
Probable	8	55	-	17
Proved Plus Probable	234	653	2	344

United States	**Estimated 2013 Average Daily Production based on Forecast Prices**			
	Light and Medium Oil (bbl/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	Total Oil Equivalent (boe/d)
Proved	8	1,033	47	227
Probable	-	-	-	-
Proved Plus Probable	8	1,033	47	227

Production History

The following tables set forth DEAL's share of average daily production volumes, royalties, production costs and the resulting netbacks for the periods indicated as at December 31, 2012:

Average Daily Production (Before Deduction of Royalties) Year Ended December 31, 2012				
	Quarter Ended			
	31-Dec-12	30-Sep-12	30-Jun-12	31-Mar-12
Oil and Natural gas liquids (bbls/d)	193	181	215	204
Gas (Mcf/d)	755	993	1,146	1,271
Total (boe/d)	319	346	406	416

Production and Netback Summary Year Ended December 31, 2012				
	Quarter Ended			
	31-Dec-12	30-Sep-12	30-Jun-12	31-Mar-12
Production Volumes:				
Oil and natural gas liquids (bbls)	17,767	16,634	19,595	18,571
Natural gas (mcf)	69,479	91,321	104,321	115,660
Total (BOE)	29,347	31,854	36,982	37,848
Average Price Received:				
Oil and natural gas liquids ($/bbls)	78.33	79.66	78.85	88.46
Natural gas (mcf)	3.44	2.49	2.16	2.47
Total ($/BOE)	55.55	48.73	47.88	50.95
Royalties ($/BOE)	8.88	7.35	7.86	8.73
Operating and Transportation Expenses ($/BOE)	25.95	37.93	22.72	25.15
Netbacks ($/BOE)	20.72	3.45	17.30	17.07

Results of Operations of Producing Activities (1)

For the years ended December 31	2012	2011
	$	$
Canada		
Oil and gas sales, net of royalties	5,765,822	7,196,464
Lease operating costs and capital taxes	(3,101,128)	(1,975,294)
Transportation costs	(660,813)	(507,959)
Amortization and depletion	(2,753,767)	(2,392,870)
Results of operations	**(749,886)**	**2,320,341**
United States		
Oil and gas sales, net of royalties	-	-
Lease operating costs and capital taxes	(31,286)	(16,227)
Transportation costs	-	-
Amortization and depletion	(12,612)	(10,483)
Results of operations	**(43,899)**	**(26,710)**
Total		
Oil and gas sales, net of royalties	5,765,822	7,196,464
Lease operating costs and capital taxes	(3,132,414)	(1,991,521)
Transportation costs	(660,813)	(507,959)
Amortization and depletion	(2,766,379)	(2,403,353)
Results of operations	**(793,785)**	**2,293,631**

(1) Non-GAAP measure

DIVIDEND POLICY

The Company has not paid any dividends on its common shares. The Company may pay dividends on its common shares in the future if it generates profits. Any decision to pay dividends on common shares in the future will be made by the board of directors on the basis of the earnings, financial requirements and other conditions existing at such time.

GENERAL DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of the Company consists of three classes of shares: an unlimited number of common shares; an unlimited number of preferred shares designated as First Preferred Shares, issuable in series; and an unlimited number of preferred shares designated as Second Preferred Shares, issuable in series.

All of the common shares of the Company have equal voting rights, and none of the common shares are subject to any further call or assessment. There are no special rights or restrictions of any nature attaching to any of the common shares and they all rank pari passu each with the other as to all benefits which might accrue to the holders of the common shares. The common shares are not convertible into shares of any other class and are not redeemable or retractable.

The First Preferred Shares have priority over the common shares and the Second Preferred Shares with respect to the payment of dividends and in the distribution of assets in the event of a winding up of the Company. The Second Preferred Shares have priority over the common shares with respect to dividends and surplus assets in the event of a winding up of the Company.

As at December 31, 2012, 148,916,374 common shares are issued and outstanding. No First Preferred Shares or Second Preferred Shares have been issued. As at the date of this AIF, 148,916,374 common shares are issued and outstanding. No First Preferred Shares or Second Preferred Shares have been issued.

As at December 31, 2012, 29,052,636 share purchase warrants are issued and outstanding. These warrants were issued in connection with debt settlement and private placement financings. 7,658,007 warrants are exercisable into common shares at prices ranging from C$0.40 to C$0.55 per share for periods ending up to November 17, 2015. 21,394,629 warrants are exercisable into common shares at prices ranging from US$0.40 to US$0.46 per share for periods ending up to June 4, 2017.

As at the date of this AIF, 29,052,636 share purchase warrants are issued and outstanding. These warrants were issued in connection with debt settlement and private placement financings. 7,658,007 warrants are exercisable into common shares at prices ranging from C$0.40 to C$0.55 per share for periods ending up to November 17, 2015. 21,394,629 warrants are exercisable into common shares at prices ranging from US$0.40 to US$0.46 per share for periods ending up to June 4, 2017.

MARKET FOR SECURITIES

Trading Price and Volume

The Company's common shares are listed for trading through the facilities of the TSX and NYSE-AMEX under the symbol "DEJ". The following table sets out, for the periods indicated, the high and low sales price and the volume of trading of the common shares of the Company on the TSX during the periods indicated. The Company ceased to trade on the TSX-V and graduated to the TSX effective November 20, 2008.

TSX

Period	High ($)	Low ($)	Volume
February 2013	0.23	0.17	1,918,900
January 2013	0.25	0.20	524,300
December 2012	0.24	0.17	552,300
November 2012	0.22	0.16	566,000
October 2012	0.24	0.19	373,100
September 2012	0.25	0.14	452,900
August 2012	0.25	0.12	721,000
July 2012	0.26	0.20	233,700
June 2012	0.26	0.23	333,100
May 2012	0.35	0.23	720,600
April 2012	0.38	0.25	520,900
March 2012	0.46	0.35	622,600
February 2012	0.50	0.41	1,385,900
January 2012	0.59	0.38	2,313,900

DIRECTORS AND OFFICERS

The following table sets forth all current directors and executive officers of Dejour as of the date of this AIF, with each position and office held by them in the Company and the period of service as such.

Name, Jurisdiction of Residence and Position (1)	Principal occupation or employment during the past 5 years	Number of Dejour Common Shares beneficially owned, directly or indirectly, or controlled or directed (2)	Percentage of Dejour Common Shares beneficially owned, directly or indirectly, or controlled or directed (2)	Director Since
Robert L. Hodgkinson British Columbia, Canada Director, Co-Chairman and Chief Executive Officer	President of a private company, Hodgkinson Equities Corporation, which provides consulting services to emerging businesses in the petroleum resource industry. Former director of Royce Resources Corp. (TSX-V:ROY.H) and Titan Uranium Inc. (TSX-V:TUE).	7,750,000	5.20%	May 18, 2004

Name, Jurisdiction of Residence and Position [(1)]	Principal occupation or employment during the past 5 years	Number of Dejour Common Shares beneficially owned, directly or indirectly, or controlled or directed [(2)]	Percentage of Dejour Common Shares beneficially owned, directly or indirectly, or controlled or directed [(2)]	Director Since
Stephen Mut Colorado, USA Director and Co-Chairman	Mr. Mut has served as CEO of Nycon Energy Consulting since his retirement from Shell in mid 2009. At Shell, Mr. Mut is served as chief executive officer of a unit of Shell Exploration and Production Company from 2000 until his retirement in 2009. Prior to that, Mr. Mut served in various executive roles at ARCO (Atlantic Richfield Company).	1,701,001	1.14%	December 17, 2009
Harrison Blacker [(4)] Colorado, U.S.A. Director, President and Chief Operating Officer of Dejour Energy (USA) Inc.	President of Dejour Energy (USA) Inc. since April 2008. Over 30 years of expertise managing oil and gas operations. Held the positions of Chief Executive Officer with China Oman Energy Company and Portfolio Manager, Latin American Business Unit and General Manager/ President of Venezuela Energy with Atlantic Richfield Corporation (ARCO) prior to joining Dejour USA.	525,678	0.35%	April 2, 2008
Richard Bachmann [(3)(4)(5)] Louisiana, U.S.A. Director	Mr. Bachmann previously served as President/CEO of EPL LLC, an energy consulting firm since his retirement from Energy Partners Ltd. in 2009. He was the founder, President and CEO of Energy Partners, an U.S. independent oil and gas exploration and production company. Prior to that, he was President of Louisiana Land & Exploration, a prominent U.S. gulf coast oil and gas explorer and producer. He began his career with Exxon serving in many executive positions both in the U.S. and internationally.	-	-	December 14, 2012
Dr. A. Gorrell [(4)(5)] British Columbia, Canada Director	Dr. Gorrell has over 30 years' experience with both private and public oil and gas property exploration and development in Western Canada and China. Dr. Gorrell has served as director, officer and controlling principal of several oil and gas ventures listed on the Toronto Stock Exchange. Currently, Dr. Gorrell is a director, President/CEO and Co-Chairman of Petromin Resources Ltd.	-	-	December 14, 2012

Name, Jurisdiction of Residence and Position [1]	**Principal occupation or employment during the past 5 years**	**Number of Dejour Common Shares beneficially owned, directly or indirectly, or controlled or directed** [2]	**Percentage of Dejour Common Shares beneficially owned, directly or indirectly, or controlled or directed** [2]	**Director Since**
Richard Kennedy [5] Alberta, Canada Director	Mr. Kennedy is a prominent barrister, solicitor and partner at Kennedy Agrios LLP, an Edmonton, Alberta based law firm focusing on commercial real estate, administrative and regulatory law.	94,900	0.06%	December 14, 2012
Craig Sturrock [3] British Columbia, Canada Director	Tax lawyer since 1971. Currently, he is a partner at Thorsteinssons LLP, and his practice focuses primarily on civil and criminal tax litigation.	650,000	0.44%	August 22, 2005
Darren Devine [3] British Columbia, Canada Director	Since 2003, Mr. Devine has been the principal of Chelmer Consulting Corp., a corporate finance consultancy. Prior to founding Chelmer Consulting, Mr. Devine practiced law with the firm of Du Moulin Black LLP, in Vancouver, British Columbia. Mr. Devine is a qualified Barrister and Solicitor in British Columbia, and a qualified solicitor in England and Wales.	-	-	December 17, 2009
David Matheson British Columbia, Canada Chief Financial Officer	Mr. Matheson has over 30 years of executive experience in the oil and gas industry in both operations and finance. He previously served as CFO and then as President of Equatorial Energy Ltd., a public Canadian oil and gas exploration & production company with operations in Canada and Indonesia. Mr. Matheson was admitted to the Institute of Chartered Accountants in British Columbia, the Northwest Territories, and Canada in 1975.	-	-	N/A

Name, Jurisdiction of Residence and Position [(1)]	Principal occupation or employment during the past 5 years	Number of Dejour Common Shares beneficially owned, directly or indirectly, or controlled or directed [(2)]	Percentage of Dejour Common Shares beneficially owned, directly or indirectly, or controlled or directed [(2)]	Director Since
Neyeska Mut EVP Operations, Dejour Energy (USA) Corp.	Engineer. Since 2000, she has been President of Nycon Energy Consulting working as an advisor to two major oil companies. Prior to forming Nycon Energy Consulting Mrs. Mut pursued international opportunities with Atlantic Richfield, ARCO. Has been with Dejour since 2008.	50,001	0.03%	N/A

(1) Each director will serve until the next annual general meeting of the Company or until a successor is duly elected or appointed in accordance with the Notice of Articles and Articles of the Company and the *Business Corporations Act* (British Columbia).

(2) The number of common shares beneficially owned, directly or indirectly, or over which control or direction is exercised is based upon information furnished to the Company by individual directors and executive officers.

(3) Member of audit committee.

(4) Member of reserve committee.

(5) Member of compensation and corporate governance committee.

Control of Securities

The aggregate number of Dejour common shares held by the directors and executive officers is 10,771,580 being 7.23% of the issued and outstanding common shares as at the date of the AIF.

Board of Directors

Brief biographies for each member of Dejour's board of directors are set forth below:

Robert L. Hodgkinson: Mr. Hodgkinson was the founder and Chairman of Optima Petroleum, which drilled wells in Alberta and the Gulf of Mexico before merging to form Petroquest Energy, a NASDAQ traded company. Subsequently, he founded and was CEO of Australian Oil Fields, which would later merge to become Resolute Energy/Cardero Energy Inc. Mr. Hodgkinson was also a Vice-President and partner of Canaccord Capital Corporation, and an early stage investor and original lease financier in Synenco Energy's Northern Lights Project in the Alberta oil sands.

Stephen Mut: Mr. Mut most recently served as chief executive officer of a unit of Shell Exploration and Production Company. Prior to joining Shell in 2000, Mr. Mut dedicated much of his career to operational and new business venture activities in the oil and gas, refining and marketing, and chemical and mining sectors at ARCO (Atlantic Richfield Company), where he served in various internationally based executive roles in both upstream and downstream businesses. His global expertise has contributed to industry successes in Europe, South America, the Asia Pacific and the United States.

Harrison Blacker: Mr. Blacker is an accomplished senior executive with over 30 years of expertise managing oil and gas operations with major corporations in the United States, South America, China and the Middle East. Prior to joining Dejour, Mr. Blacker was CEO of China Oman Energy Company, a joint venture between Oman Oil Company, IPIC and China Gas Holdings, importing and distributing LNG and LPG from the Middle East into China. Mr. Blacker held positions as VP of Business Development and Senior Investor Advisor with Oman Oil Company and Portfolio Manager, Latin American Business Unit and General Manager/ President of Venezuela Energy with Atlantic Richfield Corporation. Mr. Blacker began his career with Amoco Production Company working in offshore construction and field operations in the Gulf of Mexico.

Richard Bachmann: Mr. Bachmann previously served as President/CEO of EPL LLC, an energy consulting firm since his retirement from Energy Partners Ltd. in 2009. He was the founder, President and CEO of Energy Partners, an U.S. independent oil and gas exploration and production company. Prior to that, he was President of Louisiana Land & Exploration, a prominent U.S. gulf coast oil and gas explorer and producer. He began his career with Exxon serving in many executive positions both in the U.S. and internationally.

Dr. A. Gorrell: Dr. Gorrell has over 30 years' experience with both private and public oil and gas property exploration and development in Western Canada and China. Dr. Gorrell has served as director, officer and controlling principal of several oil and gas ventures listed on the Toronto Stock Exchange. Currently, Dr. Gorrell is a director, President/CEO and Co-Chairman of Petromin Resources Ltd.

Richard Kennedy: Mr. Kennedy is a prominent barrister, solicitor and partner at Kennedy Agrios LLP, an Edmonton, Alberta based law firm focusing on commercial real estate, administrative and regulatory law.

Craig Sturrock: Mr. Sturrock has served as a director and founding member of various public and private companies. Admitted to the British Columbia Bar in 1969, he joined Thorsteinssons LLP, tax lawyers in 1971. He served for 15 years as a tax lawyer and partner at Birnie, Sturrock & Company returning to Thorsteinssons as a partner in 1989. He is an author and speaker for the Canadian and British Columbia Bar Associations, the Continuing Legal Education Society of British Columbia and the Canadian Tax Foundation. He is also a former member of the Board of Governors of the Canadian Tax Foundation.

Darren Devine: Mr. Devine is the principal of Chelmer Consulting Corp., which provides corporate finance advisory services to private and public companies. Mr. Devine is a qualified Barrister and Solicitor in British Columbia, and a qualified solicitor in England and Wales. Prior to forming Chelmer Consulting, Mr. Devine practiced exclusively in the areas of corporate finance and securities law with a focus on cross-border finance, stock exchange listings and mergers and acquisitions with the firm DuMoulin Black LLP in Vancouver, British Columbia.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

To the knowledge of the Company, no director or executive officer of the Company is, or has been in the last ten years, a director, chief executive officer or chief financial officer of an issuer that, while that person was acting in that capacity, (a) was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under Canadian securities legislation, for a period of more than 30 consecutive days, or (b) was subject to an event that resulted, after that person ceased to be a director, chief executive officer or chief financial officer, in the issuer being the subject of a cease trade or similar order or an order that denied the issuer access to any exemption under Canadian securities legislation, for a period of more than 30 consecutive days. To the knowledge of the Company, no director or executive officer of the Company, or a shareholder holding a sufficient number of securities in the Company to affect materially the control of the Company, is or has been in the last ten years, a director or executive officer of an issuer that, while or acting in that capacity within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets. To the knowledge of the Company, in the past ten years, no such person has become bankrupt, made a proposal under any legislation related to bankruptcy or insolvency, or was subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold their assets.

Conflicts of Interest

Certain of the Company's directors and officers serve or may agree to serve as directors or officers of other reporting companies or have significant shareholdings in other reporting companies and, to the extent that such other companies may participate in ventures in which the Company may participate, the directors of the Company may have a conflict of interest in negotiating and concluding terms respecting the extent of such participation. In the event that such a conflict of interest arises at a meeting of the Company's directors, a director who has such a conflict will abstain from voting for or against the approval of such participation or such terms and such director will not participate in negotiating and concluding terms of any proposed transaction. From time to time, several companies may participate in the acquisition, exploration and development of natural resource properties thereby allowing for their participation in larger programs, permitting involvement in a greater number of programs and reducing financial exposure in respect of any one program. It may also occur that a particular company will assign all or a portion of its interest in a particular program to another of these companies due to the financial position of the company making the assignment. Under the laws of the Province of British Columbia, the directors of the Company are required to act honestly, in good faith and in the best interests of the Company. In determining whether or not the Company will participate in a particular program and the interest therein to be acquired by it, the directors will primarily consider the degree of risk to which the Company may be exposed and its financial position at that time. See also "Description of the Business – Risk Factors".

AUDIT COMMITTEE INFORMATION

The Audit Committee information required to be disclosed in an annual information form under National Instrument 52-110 (Audit Committees) is attached as Appendix "C" to this AIF and set out below under the heading "Audit Fees".

EXTERNAL AUDITOR SERVICE FEES

The following table sets out the fees billed to the Company by BDO Canada LLP for professional services rendered during fiscal years ended December 31, 2012 and December 31, 2011. During these years, BDO Canada LLP was our external auditors.

	Year ended December 31, 2012	**Year ended December 31, 2011**
	$	$
Audit Services (1)	229,950	152,639
Audit Related Services (2)	100,430	251,853
Tax Services (3)	11,210	Nil
All Other Fees (4)	27,850	24,691

NOTES:

(1) Audit fees consist of fees for the audit of the Company's annual financial statements and review of the Company's quarterly financial statements, or services that are normally provided in connection with statutory and regulatory filings or engagements.
(2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of the Company's financial statements and are not reported as Audit fees. During fiscal 2012 and 2011, the services provided in this category included reviews on IFRS conversion, consultation on accounting and audit-related matters, and review of reserves disclosure.
(3) Tax fees consist of fees for tax compliance services, tax advice and tax planning. During fiscal 2012 and 2011, the services provided in this category included assistance and advice in relation to the preparation of corporate income tax returns.
(4) The services provided in this category included all other services fees that are not reported as other categories.

LEGAL PROCEEDINGS

There are no material pending legal proceedings to which the Company is or is likely to be a party, or to which its property is subject, or which are known to the Company to be contemplated that are material to the business and affairs of the Company.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

No director, executive officer or principal shareholder of the Company, or any associate or affiliate of the foregoing, has had any material interest, direct or indirect, in any transaction within the three most recently completed financial years or during the current financial year prior to the date of this AIF that has materially affected or will materially affect the Company.

TRANSFER AGENTS AND REGISTRARS

The registrar and transfer agent of the common shares of the Company in Canada is Computershare Trust Company of Canada, 2nd Floor, and 510 Burrard Street, Vancouver, British Columbia, V6C 3B9. The registrar and transfer agent of the common shares of the Company in the United States is Computershare Trust Company, N.A., Suite #1700, 717 17th Street, Denver, CO 80202-3323.

MATERIAL CONTRACTS

There are no material contracts that were entered into within the last financial year or before the last financial year but which are still in effect, and that are required to be filed under section 12.2 of National Instrument 51-102 or would be required to be filed under section 12.2 of the Instrument but for the fact that they were previously filed.

INTERESTS OF EXPERTS

Information of an economic (including economic analysis), scientific or technical nature in respect of the Company's oil and gas projects and properties is contained in this AIF based upon the reserves report, titled "Reserve and Resource Estimation and Economic Evaluation, Dejour Energy (Alberta) Ltd.", is dated January 30, 2013 and has an effective date of December 31, 2012 prepared by AJM Deloitte; and the reserve report, titled "Reserve Evaluation Report, Dejour Energy (USA) Corp., Leasehold Garfield County, Colorado, USA, is dated March 12, 2013 and has an effective date of January 1, 2013 prepared by Gustavson Associates.

AJM and Gustavson have advised the Company that it beneficially owns, directly or indirectly, less than one percent of the outstanding common shares.

ADDITIONAL INFORMATION AND ADVISORY

Additional information relating to the Company may be found on SEDAR at www.sedar.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Company's securities, and securities authorized for issuance under equity compensation plans, where applicable, is contained in the Company's Information Circular for its most recent annual general meeting of securityholders that involved the election of directors.

Additional financial information is provided in the Company's consolidated financial statements and management's discussion and analysis for the 12 months ended December 31, 2012.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This AIF and the documents incorporated by reference herein contain "forward-looking information" and "forward-looking statements" within the meaning of Canadian securities legislation and the United States Private Securities Litigation Reform Act of 1995. The forward-looking statements and forward looking information are based upon the Company's current internal expectations, estimates, projections, assumptions and beliefs. In some cases, words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "may", "will", "potential", "proposed" and other similar words, or statements that certain events or conditions "may" or "will" occur, are intended to identify forward-looking statements and forward-looking information. These statements are not guarantees of future performance and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in the forward-looking statements or information. In addition, this AIF may contain forward-looking statements and information attributed to third party industry sources. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur. Such forward-looking statements and information in this AIF speak only as of the date of this AIF.

Forward-looking statements and information in this AIF include, but are not limited to, statements with respect to:

- drilling inventory, drilling plans and timing of drilling, re-completion and tie-in of wells;
- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production;
- drilling, completion and facilities costs;
- results of various projects of the Company;
- ability to lower cost structure in certain projects of the Company;
- growth expectations within the Company;
- timing of development of undeveloped reserves;
- the tax horizon of the Company;
- the performance and characteristics of the Company's oil and natural gas properties;
- oil and natural gas production levels;
- the quantity of oil and natural gas reserves;
- capital expenditure programs;
- supply and demand for oil and natural gas and commodity prices;
- the impact of federal, provincial, and state governmental regulation on the Company;
- expected levels of royalty rates, operating costs, general administrative costs, costs of services and other costs and expenses;
- expectations regarding the Company's ability to raise capital and to continually add to reserves through acquisitions, exploration and development;
- treatment under governmental regulatory regimes and tax laws; and
- realization of the anticipated benefits of acquisitions and dispositions.

Although the Company believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations, or the assumptions on which they are based, will prove to be correct. The Company cannot guarantee future results, levels of activity, performance or achievements. Consequently, there is no representation by the Company that actual results achieved will be the same in whole or in part as those set out in the forward-looking statements and information. Some of the assumptions on which the forward-looking statements are based are set out under "*Risk Factors*" and elsewhere in this AIF. Some of the risks and other factors, some of which are beyond the Company's control, that could cause results to differ materially from those expressed in the forward-looking statements and information contained in this AIF, are, but are not limited to:

- general economic conditions in Canada, the United States and globally;
- industry conditions, including fluctuations in the price of oil and natural gas;
- governmental regulation of the oil and gas industry, including environmental regulation;
- geological, technical, drilling and processing problems and other difficulties in producing reserves;
- failure to realize anticipated benefits of acquisitions and dispositions;
- unanticipated operating events which can reduce production or cause production to be shut in or delayed;
- failure to obtain industry partner and other third party consents and approvals, when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisitions of reserves, undeveloped land and skilled personnel;
- competition for and/or inability to retain drilling rigs and other services;
- the availability of capital on acceptable terms;
- the need to obtain required approvals from regulatory authorities; and
- the other factors disclosed under *"Risk Factors"* in this AIF.

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of factors is not exhaustive. **The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement. The Company is not under any duty to update any of the forward-looking statements after the date of this AIF to conform such statements to actual results or to changes in the Company's expectations except as otherwise required by applicable legislation.**

ABBREVIATIONS

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

Oil and Natural Gas Liquids		**Natural Gas**	
bbl	barrel	Mcf	thousand cubic feet
bbls	barrels	MCFD	thousand cubic feet per day
BOPD	barrels per day	MMcf	million cubic feet
Mbbls	thousand barrels	MMcf/d	million cubic feet per day
Mmbtu	million British thermal units	Mcfe	Thousand cubic feet of gas equivalent

Other

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

PRESENTATION OF OIL AND GAS RESERVES AND PRODUCTION INFORMATION

All oil and natural gas reserve information contained in this AIF has been prepared and presented in accordance with National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101"**). The actual oil and natural gas reserves and future production will be greater than or less than the estimates provided in this AIF. The estimated future net revenue from the production of the disclosed oil and natural gas reserves does not represent the fair market value of these reserves. **The Company has adopted the standard of 6 Mcf:1 boe when converting natural gas to barrels of oil equivalent. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

In respect of reserves data contained in this AIF, the following terms have the meanings indicated:

"Developed producing reserves" are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"Developed non-producing reserves" are those reserves that either have not been on production, or have previously been on production but are shut-in and the date of resumption of production is unknown.

"**gross**" means in relation to the Company's production or reserves, the working interest (operated or non-operated) share before deduction of royalties and without including any royalty interest.

"**net**" means in relation to the Company's production or reserves,the working interest (operated or non-operated) share after deduction of royalty obligations, plus the Company's royalty interests in production or reserves.

"**probable reserves**" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves are the targeted level of certainty.

"**proved plus probable reserves**" means the aggregate of proved reserves and probable reserves, before deduction of royalties.

"**proved reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves is the targeted level of certainty.

"**reserves**" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

"**royalties**" refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties which are dependent on selling prices, the price forecasts for the individual properties in question have been employed.

"**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned.

CONVERSION FACTORS

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	0.028
Cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
Cubic metres	bbls	6.289
Feet	metres	0.305
Metres	feet	3.281
Miles	kilometers	1.609
Kilometers	miles	0.621
Acres	hectares	0.405
Hectares	acres	2.471

APPENDIX "A"
FORM 51-101F2
REPORTS ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

5 FORM 51-101F2

REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

This is the form referred to in item 2 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("*NI 51-101*").

1. Terms to which a meaning is ascribed in *NI 51-101* have the same meaning in this form.
2. The report on *reserves data* referred to in item 2 of section 2.1 of *NI 51-101*, to be executed by one or more *qualified reserves evaluators or auditors independent* of the *reporting issuer*, shall in all material respects be as follows:

Report on Reserves Data

To the Board of Directors of Dejour Energy (USA) Corp:

1. We have evaluated the Company's reserves and resources data as at 1 January 1, 2013. The Company has gas, condensate, and natural gas liquid reserves estimated as at 1 January 2013. The resources data consist of prospective and contingent oil and gas resources estimated as at 1 January 2013. The related future net revenue has not been estimated.

2. The reserves and resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves and resources data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves and resources data are free of material misstatement. An evaluation also includes preparing estimates of reserves and resources data in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated net present value of the reserves of the Company evaluated by us as at 1 January 2013, using a forecast pricing scenario, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Report	Location of Reserves	Net Present Value of Future Net Revenue (thousands US$, before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
Letha C. Lencioni	Evaluation Report Preparation Date: 1 January 2013	Piceance Basin, Colorado, USA	0	Proved: 47,848.7 Probable: 41,744.9	0	Proved: 47,848.7 Probable: 41,744.9

5. In our opinion, the reserves evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on reserves data that we did not audit or evaluate; however, to our knowledge, all data were evaluated.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Letha C. Lencioni, Boulder, Colorado, USA, March 12, 2013

Deloitte.

NI 51-101 Form F2
Report on reserves data
by
independent qualified reserves
evaluator or auditor

To the Board of Directors of Dejour Energy (Alberta) Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).
3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year-end December 31, 2012, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management/Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited $M	Evaluated $M	Reviewed $M	Total $M
Deloitte	Dejour Energy (Alberta) Ltd. Reserve estimation and economic evaluation December 31, 2012	Canada	-	$9,749.90	-	$9,749.90

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgments regarding future events, actual events will vary and the variations may be material.

Executed as to our report referred to above:

Deloitte LLP
700, 850 – 2nd Street S.W.
Calgary, Alberta
T2P 0R8

Robin G. Bertram, P. Eng.
Partner

Execution date: January 30, 2013

APPENDIX "B"
FORM 51-101F3
Report of Management and Directors
on Reserves Data and Other Information

Management of Dejour Energy Inc. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The report of the independent reserves evaluators are summarized in the Annual Information Form of the Company dated March 18, 2013.

The reserves committee of the Company has

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The reserves committee has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The reserves committee has approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Forms 51-101F2 which are the reports of the independent qualified reserves evaluators on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "Harrison Blacker"
Harrison Blacker
Reserves Committee

(signed) "Richard Bachmann"
Richard Bachmann
Reserves Committee

(signed) "Dr. A. Gorrell"
Dr. A. Gorrell
Reserves Committee

APPENDIX "C"
DEJOUR ENERGY INC.
AUDIT COMMITTEE INFORMATION REQUIRED IN AN AIF

Audit Committee Charter

Audit Committee Mandate

The primary function of the audit committee (the "**Committee**") is to assist the Board in fulfilling its financial oversight responsibilities by reviewing the financial reports and other financial information provided by the Company to regulatory authorities and Shareholders, the Company's systems of internal controls regarding finance and accounting and the Company's auditing, accounting and financial reporting processes. Consistent with this function, the Committee will encourage continuous improvement of, and should foster adherence to, the Company's policies, procedures and practices at all levels. The Committee's primary duties and responsibilities are to:

Serve as an independent and objective party to monitor the Company's financial reporting and internal control system and review the Company's financial statements.

Review and appraise the performance of the Company's external auditors.

Provide an open avenue of communication among the Company's auditors, financial and senior management and the Board.

Composition

The Committee shall be comprised of three Directors as determined by the Board, the majority of whom shall be free from any relationship that, in the opinion of the Board, would interfere with the exercise of his or her independent judgment as a member of the Committee.

At least one member of the Committee shall have accounting or related financial management expertise. All members of the Committee that are not financially literate will work towards becoming financially literate to obtain a working familiarity with basic finance and accounting practices. For the purposes of the Company's Charter, the definition of "financially literate" is the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can presumably be expected to be raised by the Company's financial statements.

The members of the Committee shall be elected by the Board at its first meeting following the annual Shareholders' meeting. Unless a Chair is elected by the full Board, the members of the Committee may designate a Chair by a majority vote of the full Committee membership.

Meetings

The Committee shall meet a least twice annually, or more frequently as circumstances dictate. As part of its job to foster open communication, the Committee will meet at least annually with the Chief Financial Officer and the external auditors in separate sessions.

Responsibilities and Duties

To fulfill its responsibilities and duties, the Committee shall:

Documents/Reports Review

(a) Review and update this Charter annually.

(b) Review the Company's financial statements, MD&A and any annual and interim earnings, press releases before the Company publicly discloses this information and any reports or other financial information (including quarterly financial statements), which are submitted to any governmental body, or to the public, including any certification, report, opinion, or review rendered by the external auditors.

External Auditors

(a) Review annually, the performance of the external auditors who shall be ultimately accountable to the Board and the Committee as representatives of the Shareholders of the Company.

(b) Obtain annually, a formal written statement of external auditors setting forth all relationships between the external auditors and the Company, consistent with Independence Standards Board Standard 1.

(c) Review and discuss with the external auditors any disclosed relationships or services that may impact the objectivity and independence of the external auditors.

(d) Take, or recommend that the full Board take, appropriate action to oversee the independence of the external auditors.

(e) Recommend to the Board the selection and, where applicable, the replacement of the external auditors nominated annually for Shareholder approval.

(f) At each meeting, consult with the external auditors, without the presence of management, about the quality of the Company's accounting principles, internal controls and the completeness and accuracy of the Company's financial statements.

(g) Review and approve the Company's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Company.

(h) Review with management and the external auditors the audit plan for the year-end financial statements and intended template for such statements.

(i) Review and pre-approve all audit and audit-related services and the fees and other compensation related thereto, and any non-audit services, provided by the Company's external auditors. The pre-approval requirement is waived with respect to the provision of non-audit services if:

i. the aggregate amount of all such non-audit services provided to the Company constitutes not more than five percent of the total amount of revenues paid by the Company to its external auditors during the fiscal year in which the non-audit services are provided;

ii. such services were not recognized by the Company at the time of the engagement to be non-audit services; and

iii. such services are promptly brought to the attention of the Committee by the Company and approved prior to the completion of the audit by the Committee or by one or more members of the Committee who are members of the Board to whom authority to grant such approvals has been delegated by the Committee.

Provided the pre-approval of the non-audit services is presented to the Committee's first scheduled meeting following such approval such authority may be delegated by the Committee to one or more independent members of the Committee.

Financial Reporting Processes

(a) In consultation with the external auditors, review with management the integrity of the Company's financial reporting process, both internal and external.

(b) Consider the external auditors' judgments about the quality and appropriateness of the Company's accounting principles as applied in its financial reporting.

(c) Consider and approve, if appropriate, changes to the Company's auditing and accounting principles and practices as suggested by the external auditors and management.

(d) Review significant judgments made by management in the preparation of the financial statements and the view of the external auditors as to appropriateness of such judgments.

(e) Following completion of the annual audit, review separately with management and the external auditors any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information.

(f) Review any significant disagreement among management and the external auditors in connection with the preparation of the financial statements.

(g) Review with the external auditors and management the extent to which changes and improvements in financial or accounting practices have been implemented.

(h) Review any complaints or concerns about any questionable accounting, internal accounting controls or auditing matters.

(i) Review certification process.

(j) Establish a procedure for the confidential, anonymous submission by employees of the Company of concerns regarding questionable accounting or auditing matters.

Other

Review any related-party transactions.

Composition of the Audit Committee

The following are the members of the Committee:

Craig Sturrock	Independent ①	Financially literate ①
Richard Bachmann	Independent ①	Financially literate ①
Darren Devine	Independent ①	Financially literate ①

① As defined by National Instrument 52-110 ("**NI 52-110**").

Relevant Education and Experience

Craig Sturrock has 34 years of experience in the practice of law. He is a partner of the law firm Thorsteinssons LLP, specializing in tax litigation. He was a former member of the Board of Governors of Canadian Tax Foundation. He has many years of experience working with clients and Canada Revenue Agency on financial and tax matters.

Richard Bachmann previously served as President/CEO of EPL LLC, an energy consulting firm since his retirement from Energy Partners Ltd. in 2009. He was the founder, President and CEO of Energy Partners, an U.S. independent oil and gas exploration and production company. Prior to that, he was President of Louisiana Land & Exploration, a prominent U.S. gulf coast oil and gas explorer and producer. He began his career with Exxon serving in many executive positions both in the U.S. and internationally.

Darren Devine is the principal of Chelmer Consulting Corp., which provides corporate finance advisory services to private and public companies. Mr. Devine is a qualified Barrister and Solicitor in British Columbia, and a qualified solicitor in England and Wales. Prior to forming Chelmer Consulting, Mr. Devine practiced exclusively in the areas of corporate finance and securities law with a focus on cross-border finance, stock exchange listings and mergers and acquisitions with the firm DuMoulin Black LLP in Vancouver, British Columbia.

Audit Committee Oversight

At no time since the commencement of the Company's most recently completed financial year was a recommendation of the Committee to nominate or compensate an external auditor not adopted by the Board of Directors.

Reliance on Certain Exemptions

At no time since the commencement of the Company's most recently completed financial year has the Company relied on the exemptions in Sections 2.4 (De Minimis Non-audit Services), 3.2 (Initial Public Offerings), 3.3(2) (Controlled Companies), 3.4 (Events Outside the Control of Member), 3.5 (Death, Disability or Resignation of Audit Committee Member), 3.6 (Temporary Exemption for Limited and Exceptional Circumstances) or 3.8 (Acquisition of Financial Literacy) of NI 52-110, or an exemption from NI 52-110, in whole or in part, granted under Part 8 of NI 52-110.

Pre-Approval Policies and Procedures

The Committee has adopted specific policies and procedures for the engagement of non-audit services as described above under the heading "External Auditors".