



2010 ANNUAL INFORMATION FORM

March 25, 2011

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GLOSSARY OF TERMS

Capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Board of Directors means the board of directors of Bonavista.

Bonavista, we, us or our means Bonavista Energy Corporation and all its controlled entities on a consolidated basis, and where the context requires, also means our predecessor issuer, the Trust and its controlled entities on a consolidated basis prior to the completion of the Arrangement (as defined herein).

BOGL means Bonavista Oil & Gas Ltd.

BOGP means Bonavista Oil & Gas, a general partnership.

BELP means Bonavista Energy LP, a limited partnership.

Bonavista ExchangeCo means Bonavista ExchangeCo Ltd.

Bonavista Trust (2003) means Bonavista Trust (2003), a trust.

BP means Bonavista Petroleum, a general partnership.

BPL means Bonavista Petroleum Ltd.

Exchangeable Shareholders means holders of Exchangeable Shares.

Newco means Bonavista Energy Corporation prior to the completion of the Arrangement.

NuVista means NuVista Energy Ltd.

NuVista Energy means NuVista Energy, a general partnership wholly owned by NuVista.

Shareholders means holders of Common Shares and/or Exchangeable Shares, as applicable.

Trust means Bonavista Energy Trust.

Unitholders means holders of Trust Units.

Independent Engineering

COGE Handbook means Canadian Oil and Gas Evaluation Handbook.

CSA 51-324 means Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.

GLJ means GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

GLJ Report means the report prepared by GLJ dated February 25, 2011 and prepared February 23, 2011, evaluating and reviewing our evaluation of the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to certain of our oil and natural gas assets at December 31, 2010.

NI 51-101 means National Instrument 51-101– *Standards of Disclosure for Oil and Natural Gas Activities*.

Reserves Report means the GLJ Report and the Ryder Scott Report.

Ryder Scott means Ryder Scott Company, independent petroleum consultants of Calgary, Alberta.

Ryder Scott Report means the report prepared by Ryder Scott dated February 11, 2011 and prepared December 31, 2010 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to certain of our oil and natural gas assets at December 31, 2010.

Securities and Other Terms

Arrangement means the arrangement among Bonavista Energy Corporation, the Trust, BPL, Bonavista ExchangeCo, BOGL, Bonavista Trust (2003), BELP, BP and the holders of Trust Units and the holders of BPL Exchangeable Shares pursuant to Section 193 of the *Business Corporations Act* (Alberta) which commenced on December 31, 2010 and was completed on January 1, 2011.

BPL Exchangeable Shares means exchangeable shares of BPL which were exchangeable for Trust Units.

BPL Exchange Ratio means the ratio at which BPL Exchangeable Shares were exchangeable into Trust Units.

Common Shares means our issued and outstanding common shares.

Exchangeable Shares means the exchangeable shares of Bonavista which are exchangeable for Common Shares.

Exchange Ratio means the ratio at which Exchangeable Shares may be exchanged to Common Shares.

Shares means Common Shares and/or Exchangeable Shares, as applicable.

SEC means the United States Securities and Exchange Commission.

Trust Units means trust units of the Trust.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbbl	barrel
bbls	barrels
bbls/d	barrels per day
BOE or boe	barrel(s) of oil equivalent
boe/d	barrels of oil equivalent per day
MMbbls	million barrels
NGLs	natural gas liquids
Mstb	thousand stock tank barrels of oil
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent

Natural Gas

Bcf	billion cubic feet
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
mcfe	thousand cubic feet of natural gas equivalent
MMcf	million cubic feet
MMcf/d	million cubic feet per day
m ³	cubic metres
MMbtu	million British Thermal Units
GJ	gigajoule

Other

°API	the measure of the density or gravity of liquid petroleum products derived from a specific gravity
psi	pounds per square inch
m	metre(s)
ha	hectare(s)
\$000s	thousands of dollars
WTI	West Texas Intermediate

We have adopted the standard of 6 Mcf:1 bbl when converting natural gas to oil and 1 bbl:6 Mcf when converting oil to natural gas. **Boe and Mcfe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl or a Mcfe conversion of 1 bbl:6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

CONVERSIONS

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

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
Mcf	cubic metres	28.174
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	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

CONVENTIONS

Certain terms used herein are defined in the "*Glossary of Terms*". Certain other terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "CDN\$", "\$" or "dollars" are to Canadian dollars and references to US\$ are to United States dollars. Unless otherwise stated, all financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada. All operational information contained in this Annual Information Form relates to our consolidated operations unless the context otherwise requires.

NOTICE TO READER**Special Note Regarding Forward-Looking Statements**

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. In addition there are forward looking statements in this Annual Information Form under the headings: "*General Development of Our Business*" with respect to our business plan and strategies, capital expenditures and the sources of funding thereof, future acquisitions and dispositions, and the sources of funding future acquisitions; "*Description of Our Business* –

Disclosure of Reserves Data and Other Oil and Natural Gas Information" as to our reserves and future net revenues from our reserves, pricing, exchange and inflation rates, future development costs and the development of our proved undeveloped reserves and probable undeveloped reserves; the sources of funding of our future development costs and estimated interest and other costs of such funding, "*Description of Our Business – Other Oil and Natural Gas Information*" as to our future development and drilling activities and plans, our capital expenditure programs and the allocation thereof and results therefrom, expected operating costs, production estimates, marketing and hedging policies, reclamation and abandonment obligations and tax horizon. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In addition, this Annual Information Form, and the documents incorporated by reference, contain forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- drilling plans;
- projections of market prices and costs and the related sensitivities of distributions;
- supply and demand for oil and natural gas;
- dividend levels;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditure programs and the use of cash flow and bank debt to fund such programs.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of numerous known and unknown risks and uncertainties and other factors, many of which are beyond our control. Such factors include, but are not limited to:

- declines in oil and natural gas prices;
- variations in interest rates and foreign exchange rates;
- uncertainties relating to the weakened global economy and consequential restricted access to capital, stock market volatility, market valuations and increased borrowing costs;
- refinancing risk for existing debt and debt service costs;
- access to external sources of capital;
- risks associated with our hedging activities;
- third party/counterparty credit risk;
- risks associated with the exploitation of our properties and our ability to acquire reserves;
- government regulation and control and changes in governmental legislation;
- changes in income tax laws, royalty rates and other incentive programs;
- uncertainties associated with estimating oil and natural gas reserves;
- risks associated with our conversion to a corporate structure;
- risks associated with acquiring, developing and exploring for natural gas and other aspects of our operations;
- the timing of payment of dividends, if any;
- risks associated with large projects or expansion of our activities; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth;
- changes in climate change laws and other environmental regulations;
- competition in the oil and natural gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment;

- the activities of our operating activities and key personnel;
- depletion of our reserves;
- risks associated with securing and maintaining title to our properties;
- seasonality; and
- our permitted investments.

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 lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements, except as required by law.

Description of Funds from Operations and Netbacks

This Annual Information Form refers to funds from operations derived from cash provided by operating activities before changes in non-cash operating working capital and asset retirement expenditures. Funds from operations as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles, and therefore it may not be comparable with the calculation of similar measures for other entities. Funds from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow provided by operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian generally accepted accounting principles.

For more information, see our 2010 Management's Discussion and Analysis which includes a definition of "funds from operations" and reconciliation to cash provided by operating activities, which has been filed on SEDAR at www.sedar.com.

The term "netback" in this Annual Information Form is not a recognized measure under generally accepted accounting principles in Canada. We use "netback" as a key performance indicator and it is used by us to evaluate the operating performance of our petroleum and natural gas assets and is equal to production revenues including realized gains and losses on financial instrument contracts less royalties, transportation and operating expenses calculated on a boe basis. Readers are cautioned; however, that this measure should not be construed as an alternative to net earnings or cash flow from operating activities determined in accordance with generally accepted accounting principles in Canada as an indication of our performance.

Access to Documents

Any document referred to in this Annual Information Form and described as being filed on SEDAR at www.sedar.com (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at Suite 1500, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1 or on request at (403) 213-4300 or inv_rel@bonavistaenergy.com.

BONAVISTA ENERGY CORPORATION

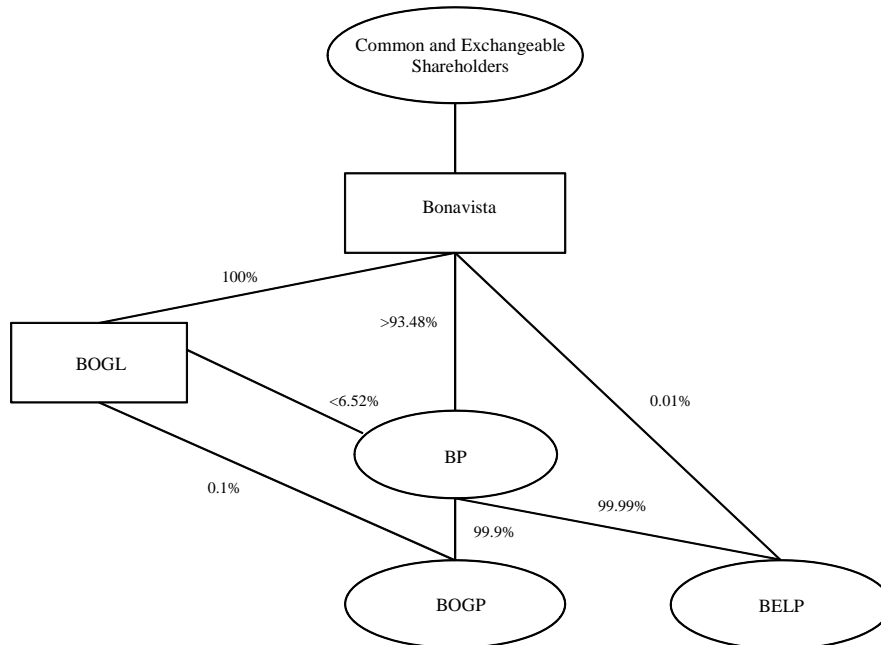
General

We are a Canadian resource corporation that is engaged in the acquisition, exploration, development and production of oil and natural gas assets. We were formed upon the amalgamation of Newco, BPL and Bonavista ExchangeCo pursuant to the Arrangement. The Arrangement involved an internal reorganization of the Trust and certain of its subsidiaries through which the trust structure was replaced with a corporate structure and the Trust was dissolved. Pursuant to the Arrangement: (i) on December 31, 2010, the Trust Units were exchanged for common shares of Newco on a one-for-one basis, the BPL Exchangeable Shares were exchanged for exchangeable shares of Newco on the basis of 2.40917 exchangeable shares of Newco for each outstanding BPL Exchangeable Share, and Newco acquired all of the assets of the Trust and assumed all of its liabilities; and (ii) on January 1, 2011, the Trust was dissolved and the common shares and exchangeable shares of Newco continued on as our Common Shares and Exchangeable Shares as a result of the amalgamation of Newco, BPL and Bonavista ExchangeCo to form Bonavista Energy Corporation. As a result of the Arrangement, we, together with our subsidiaries, own, directly or indirectly, the same assets owned by the Trust and its subsidiaries immediately prior to the Arrangement. The Arrangement has been accounted for on a continuity of interest basis as if we had always carried on the business formerly carried on by the Trust and its controlled entities on a consolidated basis. This Annual Information Form may at times refer to Common Shares and dividends which, prior to the Arrangement, were referred to as Trust Units and distributions, respectively. Unless otherwise indicated, all information presented for the pre-Arrangement period in this Annual Information Form is that of the Trust.

Our head and principal office is located at 1500, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1 and our registered office is located at 1400, 350 – 7th Avenue S.W., Calgary, Alberta, T2P 3N9.

Our Organization Structure

Subsequent to the completion of the Arrangement, on February 2, 2011, we disposed of our interest in NuVista Energy in exchange for a direct working interest in certain of NuVista Energy's oil and natural gas properties. NuVista Energy was held with NuVista of which BP had a 24.22% beneficial interest. The following diagram sets forth our organization structure as of the date hereof.



Intercorporate Relationships

The following are the names, the percentage of votes attaching to all voting securities to be beneficially owned, or controlled or directed, directly or indirectly, by us, and the jurisdiction of incorporation, continuance, formation or organization of our material subsidiaries as of the date hereof.

	Percentage of Votes (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation/ Formation
Bonavista Petroleum Ltd. (BP)	100%	General Partnership	Alberta
Bonavista Oil & Gas Ltd. (BOGL)	100%	Corporation	Alberta
Bonavista Oil & Gas (BOGP)	100%	General Partnership	Alberta
Bonavista Energy LP (BELP)	100%	Limited Partnership	Alberta

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

On July 2, 2003, BPL completed a plan of arrangement whereby holders of common shares of BPL received either Trust Units or BPL Exchangeable Shares for their common shares. Coincidental with the plan of arrangement becoming effective, certain of BPL's assets were acquired by NuVista and the common shares of NuVista were distributed to the former holders of common shares of BPL.

On January 14, 2008, we completed a \$172.2 million acquisition, net of adjustments, of producing and undeveloped oil and natural gas properties (61% natural gas weighted) in the greater Willesden Green area. This acquisition further complemented the property acquisition that we completed in the third quarter of 2007 and our pre-existing assets in this area where we have experienced success utilizing the latest horizontal, multi-stage fracture technology. Following the acquisition, we have a concentrated position in this area with numerous, low cost exploitation and optimization opportunities to pursue in the future.

On April 29, 2008, we completed a public offering of seven million Trust Units for gross proceeds of \$214.0 million. The proceeds were used to fund our expanded 2008 capital program.

On August 25, 2008, we extended the term of our \$1.0 billion syndicated bank loan facility to August 10, 2011.

On July 16, 2009, we announced that we had agreed to acquire certain long-life, liquids rich natural gas weighted properties located in our Central Alberta core area. The acquisition closed on August 20, 2009 for a cash purchase price of \$698 million. The cash to close the acquisition was funded through a combination of bank debt and a public offering of 23 million subscription receipts for gross proceeds of approximately \$387.6 million. We also granted the underwriters an over-allotment option to purchase an additional two million subscription receipts at the same price, which was exercised in full and provided us with additional gross proceeds of \$33.7 million. Upon completion of the acquisition, each subscription receipt was exchanged for one of our Trust Units. In conjunction with the acquisition, we also increased our bank facilities by \$400 million with the current members of our banking syndicate with the same maturity and financial covenants of our existing bank credit facility.

The Central Alberta acquisition was consistent with our strategy of acquiring high quality, long-life oil and natural gas assets with significant low-risk development potential at an opportune time in the cycle. The properties acquired are characterized by high working interests and operatorship with extensive gathering and processing infrastructure that enable low operating costs and efficiently accommodate production additions. These properties complement our emerging initiatives involving the use of leading technologies to access under-developed reservoirs, located in close proximity to our existing lands in our Central Alberta core area. The area is characterized as one of the most prolific multi-zone regions in western Canada with a minimum of twelve different producing horizons. The properties acquired provide significant exposure to formations such as the Glauconite, Rock Creek, Cardium, Viking and Notikewin. Utilizing leading technology, we believe that both production and recoverable reserves can be increased by over 50% from these large and scalable under-developed reservoirs. While there is extensive exploration and

development potential in many zones within the area, the primary development program will initially consist of drilling horizontal wells within the Glauconite and Cardium formations utilizing multi-stage fracture techniques paralleling our success in the area over the past year. At the time, we had identified 200 horizontal drilling locations on the properties acquired in a development program anticipated to generate attractive future development efficiencies with finding and development costs of approximately \$10 per boe and initial on-stream costs of approximately \$10,000 per boe/d. At the time, this acquisition brought our total drilling inventory to 320 primarily Glauconite and Cardium locations in the area of which 315 are expected to be drilled horizontally.

On August 31, 2009, we completed the disposition of our southeast Saskatchewan assets to Legacy Oil + Gas Inc. ("**Legacy**") for cash consideration of \$98.7 million and approximately 650,000 common shares of Legacy.

On March 23, 2010, we entered into an acquisition agreement providing for the acquisition of oil and natural gas properties and related assets in the Pine Creek/Rosevear area of Alberta (the "**Assets**") for approximately \$230 million (the "**Acquisition**"). The Acquisition closed on May 31, 2010 and has an effective date of January 1, 2010. The Assets are long-life natural gas weighted properties located adjacent to our Whitecourt property in west central Alberta. At the time of announcement, the Assets were producing approximately 3,950 boe/d, including 20.5 MMcf/d of natural gas and 540 bbls/d of oil and associated natural gas liquids. The Assets are situated on approximated 50,000 net acres of contiguous land and include operatorship of a gathering, compression and processing infrastructure with utilized capacity offering an opportunity to add future production in a timely and cost effective manner. The Acquisition was not material to the Trust taken as a whole and the Trust did not file a business acquisition report with respect to the Acquisition. The cash to close the Acquisition was funded in part through the issuance of Trust Units. Concurrent with the acquisition agreement, we entered into an agreement to sell, on a bought deal basis, 7.5 million Trust Units for gross proceeds of \$177 million. The financing closed on April 15, 2010.

In the second quarter of 2010, we entered into an uncommitted master shelf agreement allowing for an aggregate draw of up to US\$125 million in notes at a rate equal to the related US treasury rate corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance. On June 4, 2010 we drew down US\$50 million on the master shelf agreement with a coupon rate of 4.86% with US\$25.0 million maturing on June 4, 2016 and the remaining US\$25.0 million maturing on June 4, 2017.

On September 10, 2010, we combined and renewed our bank loan facilities into a single facility of \$1.4 billion with a maturity date of September 10, 2013.

On November 2, 2010, we issued by way of a private placement US\$300 million and CDN\$50 million of long-term notes with a weighted average coupon rate of 4.12% and a weighted average term of 8.8 years.

Significant Acquisitions

We have not completed any significant acquisition during our most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

Recent Developments

On January 1, 2011 we completed the Arrangement which involved an internal reorganization of the Trust and certain of its subsidiaries through which the trust structure was replaced with a corporate structure and the Trust was dissolved. Pursuant to the Arrangement: (i) on December 31, 2010, the Trust Units were exchanged for common shares of Newco on a one-for-one basis, the BPL Exchangeable Shares were exchanged for exchangeable shares of Newco on the basis of 2.40917 exchangeable shares of Newco for each outstanding BPL Exchangeable Share, and Newco acquired all of the assets of the Trust and assumed all of its liabilities; and (ii) on January 1, 2011, the Trust was dissolved and the common shares and exchangeable shares of Newco continued on as our Common Shares and Exchangeable Shares as a result of the amalgamation of Newco, BPL and Bonavista ExchangeCo to form Bonavista Energy Corporation. As a result of the Arrangement, we, together with our subsidiaries, own, directly or indirectly, the same assets owned by the Trust and its subsidiaries immediately prior to the Arrangement.

On March 3, 2011, we elected to reduce the committed amount of our bank loan facility by \$400 million from \$1.4 billion to \$1.0 billion as a result of capacity created from the issuance of senior unsecured debt and our desire to reduce the cost of carrying the larger undrawn facility.

DESCRIPTION OF OUR BUSINESS

General

We are an Alberta based corporation engaged in the business of oil and natural gas acquisition, exploration, development and production in Western Canada.

Our business plan is to create sustainable and profitable per share growth in reserves, production and cash flow in the oil and natural gas industry. To accomplish this, we intend to pursue an integrated growth strategy with active development and exploration drilling within our core areas, together with focused acquisitions, similar to the strategies previously pursued by the Trust.

All of our activities will be directed towards maximizing value creation for Shareholders. This will be achieved through a combination of investing capital to enhance the value of our assets, operating our producing oil and natural gas properties in a low cost manner to maximize the recovery of reserves, and through making monthly dividends to Shareholders. We will focus our efforts to increasing the value of our assets through development drilling and associated development activities, enhanced resource recovery activities as well as with the periodic acquisition of undeveloped and producing oil and natural gas properties. We will acquire oil and natural gas properties and primarily participate in development activities that are generally considered to be of a low to medium risk nature in the oil and natural gas industry. Also, a percentage of each year's capital budget will be devoted to moderate risk development and lower risk exploration opportunities on our properties.

Capital Expenditures

We may approve future capital expenditures or farm-outs. Future capital expenditures on our assets are intended to maintain or improve production from our properties. We may finance capital expenditures from cash flow, drawings on our bank loan facility, proceeds from the issuance of senior notes, proceeds from issuance of additional Common Shares or other securities, proceeds of disposition of oil and natural gas properties, farm-outs or with working capital.

We may acquire additional properties and related tangible equipment and fund such acquisitions from cash flow, drawings on our bank loan facility, proceeds from the issuance of senior notes, proceeds from issuance of additional Common Shares or other securities proceeds of disposition of oil and natural gas properties, farm-outs or with working capital. We may sell any of our interests in properties. In connection with the sale of any interests in our properties, we will determine whether the net proceeds of the sale should be reinvested in additional properties or capital expenditures, used to repay borrowings or distributed to our Shareholders.

Ongoing Acquisition and Disposition Activities

Potential Acquisitions

We evaluate potential acquisitions of all types of oil and natural gas and other energy related assets as part of our ongoing asset portfolio management program. We are normally in the process of evaluating several potential acquisitions at any one time which individually or together could be material. As of the date hereof, we have not reached agreement on the price or terms of any potential material acquisitions and cannot predict whether any current or future opportunities will result in one or more acquisitions for us.

Potential Dispositions and Farm-Outs

We evaluate potential dispositions of our oil and natural gas assets as part of our ongoing asset portfolio management program. In addition, we evaluate potential farm-out opportunities with other industry participants in

respect of our oil and natural gas assets in circumstances where we believe it is prudent to do so based on, among other things, our capital program, development plan timelines and the risk profile of such assets. We are normally in the process of evaluating several potential dispositions of our assets and farm-out opportunities at any one time, which individually or together could be material. As of the date hereof, we have not reached agreement on the price or terms of any potential material dispositions or farm-outs and cannot predict whether any current or future opportunities will result in one or more dispositions or farm-outs for us.

Environment Policies

We are committed to managing and operating in a safe, efficient, environmentally responsible manner in association with our industry partners and are committed to continually improving our environmental, health, safety and social performance. To fulfill this commitment, our operating practices and procedures are consistent with the requirements established for the oil and gas industry. We support and endorse the Environmental Operating Procedures developed by the Canadian Association of Petroleum Producers ("**CAPP**"). Key environmental considerations include air quality and climate change, water conservation, spill management, waste management plans, lease and right-of-way management, natural and historic resource protection, and liability management (including site assessment and remediation). These practices and procedures apply to our employees and we monitor all activities and make reasonable efforts to ensure that companies who provide services to us will operate in a manner consistent with our environmental policy.

We believe that we meet all existing environmental standards and regulations and include sufficient amounts in our capital expenditure budget to continue to meet current environmental protection requirements. These requirements apply to all operators in the oil and gas industry; therefore it is not anticipated that our competitive position within the industry will be adversely affected by changes in applicable legislation. We have internal procedures designed to ensure that detailed due diligence reviews to assess environmental liabilities and regulatory compliance are completed prior to proceeding with new acquisitions and developments.

Our environmental management plan and operating guidelines focus on minimizing the environmental impact of our operations while meeting regulatory requirements and corporate standards. Our environmental program includes: an internal environmental compliance audit and inspection program; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an effective surface reclamation program; a groundwater monitoring program; a spill prevention, response, and clean-up program; a fugitive emission survey and repair program, and an environmental liability assessment program.

We expect to incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2010, expenditures for normal compliance with environmental regulations as well as expenditures for above normal compliance were not material.

We participate in both the Canadian federal and provincial regulated greenhouse gas ("**GHG**") emissions reporting programs and continue to quantify annual GHG emissions for internal reporting purposes. We also participate in the CAPP Responsible Canadian Energy Program. Our participation in this program demonstrates a commitment to mitigate our environmental impact through monitoring metrics, identifying areas of improvement, and implementing new processes and procedures for key environmental consideration areas.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. We compete with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Our competitors include resource companies, which have greater financial resources, staff and facilities than ours. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. We believe that our competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development. See "*Risk Factors – Risks Relating to Our Business and Operations – There is strong competition relating to all aspects of the oil and gas industry*".

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing price risk management programs, as deemed necessary and through maintaining financial flexibility. See "*Risk Factors – Risks Relating to Our Business and Operations – Declines in oil and natural gas prices will adversely affect our financial condition*" and "*Risk Factors – Risks Relating to Our Business and Operations – Our hedging activities may negatively impact our income and our financial position*".

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2011 by the renegotiation or termination of contracts or subcontracts.

Material Restructuring Transactions

Other than the Arrangement, there have been no material restructuring transactions of the Trust within the three most recently completed financial years or currently proposed for us for our current financial year.

Human Resources

At December 31, 2010, we employed 310 full-time employees, including 187 office and 123 field employees.

Disclosure of Reserves Data and Other Oil and Natural Gas Information

The statement of reserves data and other oil and natural gas information set forth below is dated effective December 31, 2010. The preparation date of the statement by GLJ is February 23, 2011 and the preparation date of the statement by Ryder Scott is December 31, 2010. The Report of Management and Directors on Reserves Data and Other Information Disclosure in Form 51-101F3 and the Report on Reserves Data by GLJ and Ryder Scott in Form 51-101F2 are attached as Appendices A, B and C to this Annual Information Form.

The reserves data set forth below is based upon evaluations by GLJ and Ryder Scott and is a total summary of the GLJ Report, the Ryder Scott Report and an internal evaluation by us. Of our total net present value reserves, approximately 84% (calculated using a discount rate of 10%) were evaluated by GLJ and Ryder Scott. The balance of approximately 16% of our proved plus probable net present value reserves were evaluated internally and reviewed by GLJ. The reserves data summarizes our oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The reserves data conforms to the requirements of NI 51-101. No attempt was made to evaluate possible reserves.

All of our reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices 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 and natural gas liquid reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "*Definitions and Other Notes to Reserves Data Tables*" in conjunction with the following tables and notes. For more information as to the risks involved, see "*Risk Factors – Risks to Our Business and Operations*".

Reserves Data (Forecast Prices and Costs)

**SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	RESERVES					
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)
PROVED:						
Developed Producing	25,729	21,693	5,063	4,468	509,869	449,292
Developed Non-Producing	592	460	1,133	929	26,634	22,703
Undeveloped	6,284	4,694	502	467	299,443	266,075
TOTAL PROVED	32,605	26,847	6,698	5,864	835,946	738,070
PROBABLE	9,735	7,602	2,591	2,231	335,938	296,560
TOTAL PROVED PLUS PROBABLE	42,340	34,449	9,289	8,095	1,171,884	1,034,630

RESERVES CATEGORY	RESERVES			
	NATURAL GAS LIQUIDS		TOTAL RESERVES	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
PROVED:				
Developed Producing	24,403	18,873	140,172	119,916
Developed Non-Producing	1,000	808	7,165	5,981
Undeveloped	18,891	15,302	75,584	64,809
TOTAL PROVED	44,294	34,983	222,921	190,706
PROBABLE	19,512	15,272	87,828	74,531
TOTAL PROVED PLUS PROBABLE	63,806	50,255	310,749	265,237

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE BEFORE INCOME TAXES DISCOUNTED AT 10%/year ⁽¹⁾	
	0	5	10	15	20	(\$/boe)	(\$/Mcf)
	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)		
PROVED:							
Developed Producing	4,361,966	3,088,436	2,417,232	2,003,396	1,722,000	20.16	3.36
Developed Non-Producing	188,366	140,409	112,082	93,148	79,554	18.74	3.12
Undeveloped	2,153,730	1,393,920	974,603	716,873	545,955	15.04	2.51
TOTAL PROVED	6,704,062	4,622,765	3,503,917	2,813,417	2,347,509	18.37	3.06
PROBABLE	3,243,028	1,660,289	1,033,399	719,166	535,556	13.87	2.31
TOTAL PROVED PLUS PROBABLE	9,947,090	6,283,054	4,537,316	3,532,583	2,883,065	17.11	2.85

Note:

(1) Unit values are based on net reserve volumes.

**NET PRESENT VALUES OF FUTURE NET REVENUE
AFTER INCOME TAXES DISCOUNTED AT (%/year)**

RESERVES CATEGORY	0 (\$000s)	5 (\$000s)	10 (\$000s)	15 (\$000s)	20 (\$000s)
PROVED:					
Developed Producing	3,896,513	2,811,616	2,232,586	1,871,229	1,622,793
Developed Non-Producing	138,255	96,773	71,317	53,794	40,947
Undeveloped	1,613,244	1,030,415	708,581	511,135	380,683
TOTAL PROVED	5,648,012	3,938,804	3,012,484	2,436,158	2,044,423
PROBABLE	2,430,154	1,239,163	766,925	530,188	392,011
TOTAL PROVED PLUS PROBABLE	8,078,166	5,177,967	3,779,409	2,966,346	2,436,434

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	REVENUE (\$000s)	ROYALTIES (\$000s)	OPERATING COSTS (\$000s)	DEVELOPMENT COSTS (\$000s)	ABANDONMENT AND RECLAMATION COSTS (\$000s)	FUTURE NET REVENUE BEFORE INCOME TAXES (\$000s)	INCOME TAXES (\$000s)	FUTURE NET REVENUE AFTER INCOME TAXES (\$000s)
PROVED:								
Developed Producing	7,784,180	1,183,350	2,051,693	67,003	120,170	4,361,966	465,453	3,896,513
Developed Non-Producing	353,040	57,476	85,059	22,773	(634)	188,366	50,111	138,255
Undeveloped	4,027,463	635,921	559,355	660,405	18,051	2,153,730	540,486	1,613,244
TOTAL PROVED	12,164,683	1,876,747	2,696,107	750,181	137,587	6,704,062	1,056,050	5,648,012
PROBABLE	5,598,917	927,189	1,180,148	227,178	21,373	3,243,028	812,873	2,430,154
TOTAL PROVED PLUS PROBABLE	17,763,600	2,803,936	3,876,255	977,359	158,960	9,947,090	1,868,923	8,078,166

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS**

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year)	UNIT VALUE⁽¹⁾	
		(\$000s)	(\$/boe)	(\$/Mcfe)
Proved	Light and Medium Crude Oil (including solution natural gas and other by-products)	856,806	29.39	4.90
	Heavy Oil (including solution natural gas and other by-products)	208,082	33.67	5.61
	Natural Gas (including by-products but excluding natural gas from oil wells)	2,439,029	15.70	2.62
	Total	3,503,917	18.37	3.06
Proved plus Probable	Light and Medium Crude Oil (including solution natural gas and other by-products)	1,032,036	27.44	4.57
	Heavy Oil (including solution natural gas and other by-products)	272,974	32.14	5.36
	Natural Gas (including by-products but excluding natural gas from oil wells)	3,232,306	14.75	2.46
	Total	4,537,316	17.11	2.85

Note:

(1) Unit values are based on net reserve volumes.

Definitions and Other Notes to Reserves Data Tables

In the tables set forth above in "*Disclosure of Reserves Data and Other Oil and Natural Gas Information*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. **"Gross"** means:
 - (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;
 - (b) in relation to wells, the total number of wells in which we have an interest; and
 - (c) in relation to properties, the total area of properties in which we have an interest.

2. **"Net"** means:
 - (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves.
 - (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
 - (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

Reserve Categories

Reserves are 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

- (a) analysis of drilling, geological, geophysical and engineering data;
- (b) the use of established technology; and
- (c) specified economic conditions (see the discussion of "*Economic Assumptions*" below).

Reserves are classified according to the degree of certainty associated with the estimates.

- (a) 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.
- (b) 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.

"Economic Assumptions" means the forecast prices and costs used in the estimate:

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

- (a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
 - (i) 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.
 - (ii) 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.
- (b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, 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) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4. "**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and/or storing the oil and natural gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, natural gas lines and power lines, pumping equipment and wellhead assembly;

- (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
 - (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
 - (d) provide improved recovery systems.
5. **"Development well"** means a well drilled inside the established limits of an oil and natural gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
6. **"Exploration costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
- (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;
 - (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
 - (c) dry hole contributions and bottom hole contributions;
 - (d) costs of drilling and equipping exploratory wells; and
 - (e) costs of drilling exploratory type stratigraphic test wells.
7. **"Exploratory well"** means a well that is not a development well, a service well or a stratigraphic test well.
8. **"Service well"** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: natural gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.
9. **"Forecast Prices and Costs"**
- These are prices and costs that are:
- (a) generally acceptable as being a reasonable outlook of the future; and
 - (b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).
10. The estimates of future net revenue presented in the tables above do not represent fair market value.

Pricing Assumptions

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS ⁽¹⁾⁽²⁾⁽³⁾**

Year	OIL				NATURAL GAS					
	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Hardisty Heavy 12° API (\$Cdn/bbl)	Cromer Medium Stream Quality (\$Cdn/bbl)	AECO Natural Gas Price (\$Cdn/MMbtu)	Spec Ethane (\$Cdn/bbl)	Edmonton Propane (\$Cdn/bbl)	Edmonton Butane (\$Cdn/bbl)	Edmonton Pentane Plus (\$Cdn/bbl)	Exchange Rate \$US/\$Cdn
2011	88.00	86.22	68.79	82.78	4.16	13.66	54.32	67.26	90.54	0.98
2012	89.00	89.29	68.33	83.04	4.74	15.68	56.25	68.75	91.96	0.98
2013	90.00	90.92	67.03	83.64	5.31	17.62	57.28	70.01	92.74	0.98
2014	92.00	92.96	67.84	84.59	5.77	19.21	58.56	71.58	94.82	0.98
2015	95.17	96.19	70.23	87.54	6.22	20.79	60.60	74.07	98.12	0.98
2016	97.55	98.62	72.03	89.75	6.53	21.85	62.13	75.94	100.59	0.98
2017	100.26	101.39	74.08	92.26	6.76	22.62	63.87	78.07	103.42	0.98
2018	102.74	103.92	75.95	94.57	6.90	23.14	65.47	80.02	106.00	0.98
2019	105.45	106.68	78.00	97.08	7.06	23.67	67.21	82.15	108.82	0.98
2020	107.56	108.84	79.59	99.04	7.21	24.20	68.57	83.80	111.01	0.98
Thereafter	2%/year	2%/year	2%/year	2%/year	2%/year	2%/year	2%/year	2%/year	2%/year	0.98

Notes:

- (1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
- (2) The pricing forecast used in determining the value of cash flow is based on the January 1, 2011 forecast determined by GLJ.
- (3) Inflation rate is 2.00% per year.

Weighted average historical prices we realized for the year ended December 31, 2010, were \$4.50/Mcf for natural gas, \$73.46/bbl for light and medium oil, \$45.01/bbl for natural gas liquids and \$60.72/bbl for heavy oil.

Reserves Reconciliation

**RECONCILIATION OF
GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS**

	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Total Proved (Mbbls)	Probable (Mbbls)	Total Proved Plus Probable (Mbbls)	Total Proved (Mbbls)	Probable (Mbbls)	Total Proved Plus Probable (Mbbls)
December 31, 2009	32,224	10,387	42,611	7,604	3,097	10,701
Discoveries	-	-	-	-	-	-
Extensions	2,691	776	3,467	682	217	898
Infill Drilling	425	248	673	156	49	204
Improved Recovery	77	15	93	353	39	391
Technical Revisions	63	(1,773)	(1,707)	(69)	(536)	(602)
Acquisitions	1,185	184	1,369	-	-	-
Dispositions	(478)	(103)	(580)	(282)	(275)	(557)
Economic Factors	-	-	-	-	-	-
Production	(3,586)	-	(3,586)	(1,746)	-	(1,746)
December 31, 2010	32,605	9,734	42,340	6,698	2,591	9,289

	ASSOCIATED AND NON-ASSOCIATED NATURAL GAS			NATURAL GAS LIQUIDS		
	Total Proved (MMcf)	Probable (MMcf)	Total Proved Plus Probable (MMcf)	Total Proved (Mbbbls)	Probable (Mbbbls)	Total Proved Plus Probable (Mbbbls)
December 31, 2009	729,187	306,300	1,035,487	31,828	14,192	46,019
Discoveries	-	-	-	-	-	-
Extensions	33,690	6,181	39,871	1,810	477	2,287
Infill Drilling	50,111	23,508	73,619	3,272	1,582	4,854
Improved Recovery	3,121	479	3,599	172	28	200
Technical Revisions	19,379	(31,229)	(11,851)	8,233	2,068	10,301
Acquisitions	99,440	35,971	135,411	3,250	1,184	4,434
Dispositions	(6,728)	(3,135)	(9,862)	(28)	(8)	(36)
Economic Factors	(4,576)	(2,137)	(6,712)	(25)	(10)	(35)
Production	(87,678)	-	(87,678)	(4,218)	-	(4,218)
December 31, 2010	835,946	335,938	1,171,884	44,294	19,513	63,806

	OIL EQUIVALENT		
	Total Proved (Mboe)	Probable (Mboe)	Total Proved Plus Probable (Mboe)
December 31, 2009	193,187	78,726	271,913
Discoveries	-	-	-
Extensions	10,797	2,500	13,297
Infill Drilling	12,205	5,797	18,002
Improved Recovery	1,122	162	1,284
Technical Revisions	11,462	(5,447)	6,015
Acquisitions	21,008	7,363	28,371
Dispositions	(1,909)	(907)	(2,816)
Economic Factors	(788)	(366)	(1,154)
Production	(24,163)	-	(24,163)
December 31, 2010	222,921	87,828	310,749

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ and Ryder Scott in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "Risk Factors".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years and, in the aggregate, before that time.

TIMING OF INITIAL PROVED UNDEVELOPED RESERVES ASSIGNMENT GROSS RESERVES FIRST ATTRIBUTED BY YEAR								
Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior	5,944	5,944	719	719	26,825	26,825	1,576	1,576
2008	1,883	7,455	255	599	29,714	52,336	1,394	2,688
2009	734	6,031	212	302	196,348	236,577	10,002	11,708
2010	1,664	6,192	309	502	102,116	290,934	5,066	18,534

Of our total proved plus probable reserves, 75.6 MMboe or 24% are proved undeveloped reserves. The Hoadley Glauconite property accounts for 51.3 MMboe or 68% of our proved undeveloped reserves. The next largest undeveloped reserves property is at Pine Creek, located in our Western region, and it accounts for 5.7 MMboe or 7.5% of these undeveloped reserves. In 2011 and 2012 capital expenditures of \$164 million and \$200 million will be invested on our proved undeveloped reserves. Of this \$364 million, \$165 million will be spent on the Hoadley Glauconite property and \$34 million on the Pine Creek property.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

TIMING OF INITIAL PROBABLE UNDEVELOPED RESERVES ASSIGNMENT GROSS RESERVES FIRST ATTRIBUTED BY YEAR								
Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior	3,583	3,583	300	300	21,733	21,733	1,268	1,268
2008	1,109	4,117	106	276	11,587	31,718	685	1,773
2009	549	2,748	96	152	125,127	160,550	6,377	7,752
2010	1,830	2,857	182	297	99,279	184,732	4,655	11,557

Probable undeveloped reserves account for 47.1 MMboe or 15% of the total proved plus probable reserves. In 2011 and 2012 capital expenditures of \$27 million and \$69 million will be invested on these probable undeveloped reserves. Of this \$96 million of capital expenditure, \$37 million will be spent on our Hoadley Glauconite property, \$8 million at our Wilson Creek property and \$6 million at our Lanaway property.

Significant Factors or Uncertainties

Our evaluated oil and natural gas properties have no material extraordinary risks or uncertainties beyond those, which are inherent in an oil and natural gas producing company as described under the heading "*Management's Discussion and Analysis*" in our 2010 Management's Discussion and Analysis, which has been filed on SEDAR at www.sedar.com. See also "*Risk Factors*" below.

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

Year	FORECAST PRICES AND COSTS	
	Total Proved Reserves (\$000s)	Total Proved Plus Probable Reserves (\$000s)
2011	223,636	253,419
2012	214,107	286,893
2013	139,718	199,998
2014	93,025	138,360
2015	71,210	85,161
Remaining	8,485	13,528
Total (Undiscounted)	750,181	977,359

We expect to fund the development costs of our reserves through a combination of internally generated cash flow and debt. We expect to withhold approximately 65% to 70% of cash flow to assist in funding development activities.

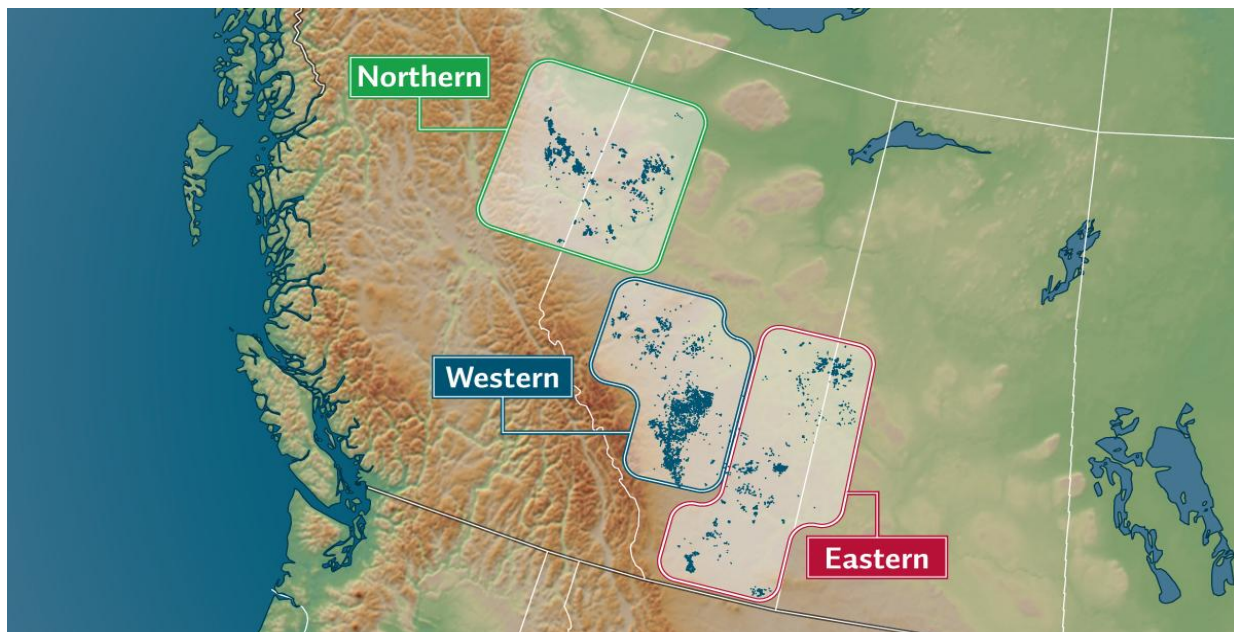
There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the reserve reports. Failure to develop those reserves would have a negative impact on our future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any property uneconomic.

Other Oil and Natural Gas Information

Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2010. The term "net", when used to describe our share of production, means the total of our working interest share before deduction of royalties owned by others. Reserve amounts are stated, before deduction of royalties, at December 31, 2010, based on January 1, 2011 forecast price and cost assumptions. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2010. **The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.**



Our major properties are concentrated in three regions within Alberta, British Columbia and Saskatchewan. Each region offers a large land base, a vast seismic database, and significant ownership and operatorship in production facilities.

MAJOR PROPERTIES:

NORTHERN REGION	CURRENT PRODUCTION	UNDEVELOPED LAND	GROSS RESERVES	2011 DRILLING PROGRAM
	(boe/d)	(net acres)	(MMboe)	(# of gross locations)
North Peace River	5,500	154,110	16.1	4
Northeast British Columbia	10,600	233,128	46.6	12
Total Northern Region	16,100	387,238	62.7	16
WESTERN REGION	CURRENT PRODUCTION	UNDEVELOPED LAND	GROSS RESERVES	2011 DRILLING PROGRAM
	(boe/d)	(net acres)	(MMboe)	(# of gross locations)
North Central	6,500	92,969	25.4	14
Central	22,300	410,959	140.9	55
South Central	10,900	361,420	44.0	10
Total Western Region	39,700	865,348	210.3	79
EASTERN REGION	CURRENT PRODUCTION	UNDEVELOPED LAND	GROSS RESERVES	2011 DRILLING PROGRAM
	(boe/d)	(net acres)	(MMboe)	(# of gross locations)
Southern	3,700	23,099	16.4	1
Provost	2,800	38,637	8.9	18
Heavy Oil ⁽¹⁾	5,500	208,545	12.4	15
Total Eastern Region	12,000	270,281	37.7	34
Grand Total	67,800	1,522,867	310.7	129

Note:

(1) Includes Northeast Alberta gas production.

Northern Region

The Northern Region represents approximately 28% of our current natural gas production and 17% of our oil and liquids production. Production in this region originates primarily from the Mississippian, Triassic and Cretaceous aged formations. In 2010, we invested \$31.1 million to expand our land position in this region.

Production from this region flows mainly through our 31 owned and operated compression facilities. Our average working interest in these facilities is approximately 86%. This production is currently 72% weighted to natural gas resulting in a low cost structure with ample capacity to add incremental production efficiently. In 2010, production from the Northern Region averaged 68.0 MMcf/d of natural gas and 4,431 bbls/d of oil and liquids for a total of 15,673 boe/d. We also own 387,238 net acres of prospective undeveloped land in the region with an average working interest of approximately 72%.

The Northern Region includes a diversified property base, primarily operated by us, which in 2010 collectively accounted for:

- 27% of total exploration and development expenditures;
- 6% of total acquisition expenditures, excluding dispositions;
- 24% of total production volumes;
- 20% of total proved plus probable reserves at December 31, 2010; and

- 25% of net undeveloped land holdings at December 31, 2010.

In 2010, we spent \$92.8 million on exploration and development projects including the drilling of 18 wells. In 2011, we expect to spend approximately \$40.0 million in the Northern Region, which includes drilling and equipping 16 new wells focused on incremental development of both oil and liquids rich natural gas reservoirs characterized as being heterogeneous in nature with significant resources in place. These capital expenditures are expected to result in steady production volumes when comparing 2010 to 2011 and include the impact of the divestiture of our Clearhills property (approximately 500 boe/d) which closed in December 2010.

Major Properties

Northeast British Columbia – All properties are geographically located within a 200 mile radius of Fort St. John, British Columbia. Most of our natural gas produced in this area of Northeast British Columbia is processed and shipped to market by Spectra Energy processing plants in which we do not have working interest ownership. 2010 has been characterized by significant land acquisitions in an emerging Montney opportunity in Blueberry. Over \$30 million has been spent acquiring 50 net sections of Montney rights in an area of the play considered to contain liquid rich natural gas. Our efforts throughout 2011 will be focused on further delineation of this opportunity through the drilling of 1-2 additional wells, an extensive 3D seismic program, and reservoir simulation work in an attempt to establish a development program for 2012 and beyond. Our British Columbia assets currently produce 10,600 boe/d, a rate that has remained relatively stable over the past four years.

North Peace River – Our North Peace River district located north of Grande Prairie is 68% natural gas weighted and almost entirely operated by us. We drilled two oil wells in this area in 2010. In 2011, we anticipate spending approximately \$14 million where we will drill 4 wells, 3 of which will be horizontal oil wells. Approximately 22% of our capital budget for this area will be allocated to recompletion opportunities and well optimization with the mandate to maintain current production levels.

Western Region

The Western Region represents approximately 62% of our current natural gas production and 52% of our oil and liquids production. Production originates from multiple formations as deep as the Beaverhill Lake formation in the Edson area and as shallow as the Edmonton Sands formation in the Sylvan Lake area. Throughout 2010, we have continued to focus on medium to deep oil and liquids rich natural gas productive formations by drilling 90 wells, 78 of which were drilled and completed utilizing horizontal multi-stage stimulation technology.

Production from the Western Region in 2010 averaged 139.8 MMcf/d of natural gas and 12,669 bbls/d of light oil and liquids for a total of 36,658 boe/d. During 2010, we invested \$470.7 million of capital in the Western Region including \$245.6 million directed toward property acquisitions and dispositions, and \$225.2 million on development activities. This exploration and development program resulted in 63 natural gas wells and 26 oil wells for an overall success rate of 99%.

The Western Region includes a balanced portfolio of both oil and natural gas, primarily operated by us, which in 2010 collectively accounted for:

- 64% of total exploration and development expenditures;
- 94% of total acquisition expenditures, excluding dispositions;
- 55% of total production volumes;
- 68% of total proved plus probable reserves at December 31, 2010; and
- 57% of net undeveloped land holdings at December 31, 2010.

In 2011, we plan capital expenditures of approximately \$285 million in the Western Region. This includes a 79 well drilling program of which 95% will utilize horizontal multi-stage stimulation technology capitalizing on our success

with these techniques over the past year. With this capital spending, we anticipate production additions of approximately 22,700 boe/d. In 2011, we expect the average production to be 42,970 boe/d for this region.

Major Properties

North Central – In the second quarter of 2010 we closed the acquisition of approximately 3,500 boe/d of primarily operated, high quality, low cost production in the Edson area of Alberta. The assets also included an extensive gathering system and two operated processing plants with a combined unutilized capacity of 60 MMcf/d of raw gas. In 2011, we expect to drill 14 wells in this area of the Deep Basin. This area presents opportunity in the form of low recovery to date, heterogeneous reservoirs amenable to the application of horizontal development. We currently produce approximately 6,500 boe/d in this area.

Central – Over the past few years, we have amassed a large concentrated land position in this multi-zone area characterized by large heterogeneous reservoirs with generally low recoveries to date. The area is accessible year-round and is in close proximity to service providers offering the opportunity to maintain our existing low-cost structure. Throughout the fourth quarter of 2010, we began construction of an 80 MMcf/d compressor station that ties into the Keyera Rimbey Gas Processing Plant. This facility will provide ample capacity for the long term, consistent development of our liquids rich Hoadley Glauconite natural gas resource and will result in attractive processing fees, enhanced liquid recoveries and an opportunity to grow production efficiently. This facility will be commissioned in the second quarter of 2011. In addition, we have demonstrated continuous improvement with the development of our light oil Cardium opportunities throughout this property. To the end of 2010, we have drilled 27 Cardium horizontals across the Western Region with our results improving immensely over time. Current production levels in the Central area are approximately 22,300 boe/d and in 2011, we will spend approximately \$180 million on development activities, drilling 55 wells of which 98% will be horizontal in nature. This level of activity will add approximately 16,200 boe/d of incremental volume resulting in a 2011 exit production of 27,600 boe/d.

South Central – In 2011 we expect to drill 10 wells and spend \$46.2 million in total on development activities. Similar to our Central area, this area offers significant development opportunity as a result of our 361,420 net undeveloped acres and the multi-zone nature of this area. In 2011, we will pursue the horizontal development of the Cardium, Viking, Elkton, and Ellerslie formations. We currently produce 10,900 boe/d in this area.

Eastern Region

The Eastern Region represents approximately 10% of our current natural gas production, 100% of our heavy oil production, and 30% of our total oil and liquids production. Natural gas and heavy oil production is derived from a multitude of Upper and Lower Cretaceous sands.

Production from the Eastern Region in 2010 averaged 32.6 MMcf/d of natural gas, 4,787 bbls/d of heavy oil and 4,294 bbls/d of light and medium oil, for a total of 13,928 boe/d. We operate 26 natural gas and oil facilities in the Eastern Region.

During 2010, we invested \$31.8 million in the Eastern Region. This investment included the drilling of 32 wells with a 97% success rate, resulting in 15 medium gravity wells and 16 heavy oil wells. At December 31, 2010, undeveloped land position in this region was 270,281 net acres.

The Eastern Region in 2010 collectively accounted for:

- 9% of total exploration and development expenditures;
- 21% of total production volumes;
- 12% of total proved plus probable reserves at December 31, 2010; and
- 18% of undeveloped land at December 31, 2010.

In 2011, we plan to invest approximately \$37 million in the Eastern Region to drill 34 wells. The low risk nature of the area creates a high degree of certainty with these drilling prospects. The Eastern Region is forecasted to average 11,258 boe/d in 2011 with this level of capital activity.

Major Properties

Heavy Oil – We have been operating in the Lloydminster area for ten years. In 2011, we plan to spend \$15.5 million drilling 15 wells and performing numerous recompletions and workovers. We anticipate production to remain stable at approximately 5,160 boe/d throughout 2011.

Provost – The greater Provost area accounts for 23% of the Eastern Region's production. This stable natural gas and crude oil production is currently producing 2,800 boe/d and is derived primarily from the shallow Cretaceous sands prevalent throughout the area. We operate or have an interest in several natural gas facilities and pipeline gathering systems in the area, resulting in low cost reserve and production additions in 2010 and beyond. In 2011, we plan to spend approximately \$12 million, drilling 18 oil wells, most of which will utilize horizontal multi-stage stimulation technology to enhance the recovery of existing oil pools throughout the area.

Southern – Our Barons oil pool in Lethbridge continues to exhibit an extremely shallow decline and is currently producing approximately 1,425 bbls/d of light 38° API oil under a secondary recovery scheme. At our Manyberries property, as our waterflood programs are optimized, we anticipate long-term stable production with up to 40% of the original oil in place estimated for ultimate recovery from these pools. In 2011, we expect to spend \$9.0 million in this Southern area most of which will be committed to workover maintenance and the continuous optimization of our numerous secondary recovery schemes. We currently produce approximately 3,700 boe/d in this area.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2010:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,642	1,143	1,803	1,138	3,001	1,983	1,864	1,120
British Columbia	13	6	47	24	231	203	250	210
Saskatchewan	57	54	68	38	63	57	151	134
Total	1,712	1,203	1,918	1,200	3,295	2,243	2,265	1,464

Properties with No Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2010:

	Undeveloped Acres	
	Gross	Net
Alberta	1,557,107	1,216,010
British Columbia	334,351	233,128
Saskatchewan	77,229	73,729
Total	1,968,687	1,522,867

Our rights to explore, develop and exploit approximately 214,369 net acres of our undeveloped land holdings may expire on or before December 31, 2011 should we elect not to farm out or drill these particular lands. There are no material drilling commitments associated with the land holdings expiring by December 31, 2011.

In instances where we hold separate leases in different formations under the same surface area and pay annual rentals for each separate lease, both the gross and net acres for each lease within this surface area are accounted for in our acreage calculation.

Forward Contracts

In the normal course of operations we are exposed to market risks that result from the fluctuation in commodity prices, foreign exchange rates and interest rates. A variety of derivative instruments are used to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio among a number of financially sound counterparties. For information in relation to our marketing arrangements, see "*Marketing Arrangements*".

For details of material commitments to sell natural gas and crude oil which were outstanding at December 31, 2010, see note 11 to our consolidated financial statements for the year ended December 31, 2010, which are incorporated herein by reference.

Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment and reclamation costs for surface leases, wells, facilities, and pipelines which are expected to be incurred by us for the periods indicated:

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted (\$000s)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% (\$000s)
Total liability as at December 31, 2010	775,976	115,758
Anticipated to be paid in 2011	24,861	22,076
Anticipated to be paid in 2012	24,297	19,614
Anticipated to be paid in 2012	24,783	18,188

As at December 31, 2010, we had 5,691 net wells either producing or shut-in for which we expect to incur abandonment and reclamation costs.

The future net revenues disclosed in this Annual Information Form based on the GLJ Report and the Ryder Scott Report do not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. The GLJ Report and the Ryder Scott Report deducted \$137.6 million (undiscounted) and \$49.5 million (10% discount using forecast prices and costs for proved reserves) for well abandonment costs in estimating the future net revenue disclosed in this Annual Information Form.

Tax Horizon

Prior to the completion of the arrangement, we were a mutual fund trust and were only taxable on income that was not distributed or distributable to our unitholders. We did not pay Canadian income taxes in 2010. As of January 1, 2011, we are a taxable corporation under the *Income Tax Act (Canada)* and are liable for federal and provincial income taxes on taxable income that we are unable to shelter with our available tax pools. We do not expect to be cash taxable in 2011.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2010:

Expenditure	Year Ended December 31, 2010 (\$000s)
Property acquisition costs:	
Proved properties ⁽¹⁾	220,514
Unproved properties	71,444
Development costs ⁽²⁾	234,006
Exploration costs ⁽³⁾	42,612
Other	1,419
Total	569,995

Notes:

- (1) Acquisitions are net of dispositions of properties.
- (2) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.
- (3) Geological and geophysical capital expenditures and drilling costs for exploration wells drilled.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2010:

	Development		Exploratory	
	Gross	Net	Gross	Net
Light and Medium Oil	42	20.7	3	2.2
Natural Gas	72	54.5	5	3.5
Heavy Oil	12	9.7	4	4.0
Dry	-	-	2	1.5
Total	126	84.9	14	11.2

In 2011, we are forecasting to spend between \$345 and \$375 million on our exploration and development program, which contemplates the drilling of between 125 to 135 wells within our core regions. For details on our important current and likely exploration and development activities, see "Description of Our Business – Disclosure of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Oil and Natural Gas Properties" in this Annual Information Form.

Production Estimates

The following table sets out our gross production estimated in the GLJ Report and the Ryder Scott Report for the year ended December 31, 2011, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained under "Description of Our Business – Disclosure of Reserves Data and Oil and Natural Gas Information":

	Natural Gas (Mcf/d)	Light and Medium Oil (bbls/d)	Natural Gas Liquids (bbls/d)	Heavy Oil (bbls/d)	BOE (boe/d)
Total Proved	245,372	9,683	11,885	4,554	67,018
Total Proved plus Probable	256,227	10,101	12,535	5,140	70,480

The Hoadley Glauconite property accounts for 20% of the estimated production disclosed. No other individual property accounts for 5% or more of the estimated production disclosed.

Production History and Prices Received

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarters Ended			
	2010			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production:				
Natural Gas (Mcf/d)	249,691	248,495	238,193	225,108
Light and Medium Crude Oil (bbls/d)	9,955	9,818	9,763	9,796
Natural Gas Liquids (bbls/d)	12,387	11,870	11,284	10,685
Heavy Oil (bbls/d)	4,350	4,925	5,140	4,735
Combined (boe/d)	68,307	68,029	65,885	62,734
Average Price Received:				
Natural Gas (\$/Mcf)	4.08	4.12	4.47	5.46
Light and Medium Crude Oil (\$/bbl)	76.29	70.05	71.61	75.85
Natural Gas Liquids (\$/bbl)	45.15	40.85	44.44	50.17
Heavy Oil (\$/bbl)	61.68	58.24	57.11	66.41
Combined (\$/boe)	38.13	36.49	38.82	44.99
Royalties:				
Natural Gas (Mcf/d)	0.37	0.40	0.40	0.60
Light and Medium Crude Oil (bbls/d)	9.76	11.06	11.98	12.77
Natural Gas Liquids (bbls/d)	11.81	8.60	10.47	12.17
Heavy Oil (bbls/d)	10.71	9.97	10.73	12.08
Combined (boe/d)	5.58	5.29	5.85	7.13
Production Costs:				
Natural Gas (Mcf/d)	1.10	1.08	1.10	1.24
Light and Medium Crude Oil (bbls/d)	9.03	8.65	8.92	9.65
Natural Gas Liquids (bbls/d)	9.03	8.65	8.92	9.65
Heavy Oil (bbls/d)	14.46	14.47	14.35	14.51
Combined (boe/d)	7.88	7.75	7.94	8.71
Netback Received:				
Natural Gas (Mcf/d)	2.61	2.64	2.97	3.62
Light and Medium Crude Oil (bbls/d)	57.50	50.34	50.71	53.43
Natural Gas Liquids (bbls/d)	24.31	23.60	25.05	28.35
Heavy Oil (bbls/d)	36.51	33.80	32.03	39.82
Combined (boe/d)	24.67	23.45	25.03	29.15

The following table indicates our average daily production from our core regions for the year ended December 31, 2010:

	Natural Gas (Mcf/d)	Light and Medium Oil (bbls/d)	NGLs (bbls/d)	Heavy Oil (bbls/d)	BOE (boe/d)
Northern	68,080	2,408	1,917	-	15,673
Western	142,155	3,486	9,480	-	36,658
Eastern	30,226	3,939	165	4,787	13,928
Total	240,461	9,833	11,562	4,787	66,259

Marketing Arrangements

Natural Gas

We continue to maintain a risk-mitigating strategy and develop a diverse natural gas sales portfolio, which encompasses a variety of pricing mechanisms and term commitments. Our natural gas portfolio includes sales to industrial customers, distribution companies and traditional aggregators.

In addition, we have adopted a disciplined commodity hedging program. The purpose of the hedging program is to reduce volatility in the financial results, protect acquisition economics and stabilize cash flow and Shareholder's dividends against the unpredictable commodity price environment. At any given period of time, our hedging strategy is restricted to a maximum hedge position of 60% of forecasted production, net of royalties, for terms not exceeding two years and primarily utilizing costless collars. In order to control and manage credit risk and ensure competitive bids, we engage a number of reputable counterparties for our transactions.

The integration and application of these strategies resulted in an average realized price of \$4.50/Mcf in 2010 compared to \$4.78/Mcf in 2009. For 2011, we are forecasting our natural gas price to average \$4.25/Mcf based on an expected average 2011 NYMEX price of US \$4.42/MMBtu and an exchange rate of US \$1.0163/CDN \$1.00.

Oil and Liquids

We sell our oil and natural gas liquids production to a variety of customers. This allows us to benefit from specific regional advantages while maintaining pricing and delivery flexibility. In 2010, our average realized oil and liquids price was \$58.56/bbl compared to \$58.18/bbl in 2009. Consistent with our natural gas strategy, our marketing objectives include protecting or securing minimum prices for up to 60% of our net production for terms not exceeding two years. Our crude oil hedging strategy primarily employs costless collars. Our average crude oil production quality is approximately 28° API. Our 2011 forecast is based on a WTI price of US\$102.92/ bbl and an exchange rate of US \$1.0163/CDN \$1.00, which converts to approximately CDN\$101.27/bbl realized at the wellhead.

Acquisitions and Dispositions

During 2010, we completed 18 property transactions including the acquisition and disposition of oil and natural gas properties. In aggregate, net of dispositions, we made \$220.5 million of property acquisitions in the year.

SHARE CAPITAL

We are authorized to issue an unlimited number of Common Shares without nominal or par value, an unlimited number of Exchangeable Shares without nominal or par value and 10,000,000 preferred shares, issuable in series. A description of our share capital is set forth below. For a complete description of our share capital, reference should be made to our Articles, a copy of which has been filed on SEDAR at www.sedar.com.

Common Shares

Our Common Shares have the following rights, privileges, restrictions and conditions:

Voting Rights: Holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of our Shareholders (other than meetings of a class or series of our shares other than the Common Shares).

Dividends: Holders of Common Shares are entitled to receive dividends as and when declared by our Board of Directors on the Common Shares as a class, subject to the prior satisfaction of all preferential rights to dividends attached to shares of other classes of our shares ranking in priority to the Common Shares in respect of dividends.

Ranking: In the event of any liquidation, dissolution or winding-up of us, whether voluntary or involuntary, or any other distribution of our assets among our Shareholders for the purpose of winding-up our affairs, and subject to

prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of our shares ranking in priority to the Common Shares in respect of return of capital on dissolution, holders of Common Shares are entitled to share rateably, together with the holders of shares of any other class of our shares ranking equally with the Common Shares, in respect of return of a capital on dissolution, in such of our assets as are available for distribution.

Preferred Shares

The preferred shares are issuable in one or more series. Our Board of Directors is empowered to fix the number of preferred shares that will form each such series and to fix the designation, rights, privileges, restrictions and conditions to be attached to the preferred shares of such series. Our Board of Directors may at any time or from time to time change the rights, privileges, restrictions and conditions attached to unissued shares of any series of Preferred Shares.

Voting Rights: The voting rights attached to the Preferred Shares shall be limited to one vote per Preferred Share at any meeting where the Preferred Shares and Common Shares vote together as a single class;

Ranking: The Preferred Shares of each series shall rank on parity with the Preferred Shares of every other series with respect to accumulated dividends and return of capital. The Preferred Shares shall be entitled to a preference over the Common Shares, the Exchangeable Shares and over any other of our shares ranking junior to the Preferred Shares with respect to priority in the payment of dividends and in the distribution of assets in the event of our liquidation, dissolution or winding-up, whether voluntary or involuntary, or any other distribution of our assets among our shareholders for the purpose of winding-up our affairs. If any cumulative dividends or amounts payable on a return of capital are not paid in full, the Preferred Shares of all series shall participate rateably in respect of such dividends, including accumulations, if any, in accordance with the sums that would be payable on such shares if all such dividends were declared and paid in full, and in respect of any repayment of capital in accordance with the sums that would be payable on such repayment of capital if all sums so payable were paid in full; provided, however, that in the event of there being insufficient assets to satisfy in full all such claims as aforesaid, the claims of the holders of the Preferred Shares with respect to repayment of capital shall first be paid and satisfied and any assets remaining thereafter shall be applied towards the payment in satisfaction of claims in respect of dividends.

The rights, privileges, restrictions and conditions attaching to the Preferred Shares as a class as provided herein and as may be provided from time to time may be repealed, altered, modified, amended or amplified or otherwise varied only with the sanction of the holders of the Preferred Shares given in such manner as may then be required by law, subject to a minimum requirement that such approval be given by resolution passed by the affirmative vote of a least two-thirds of the votes cast at a meeting of holders of Preferred Shares duly called for such purpose and held upon at least 21 days' notice at which a quorum is present comprising at least two persons present, holding or representing by proxy at least 20% per cent of the outstanding Preferred Shares or by a resolution in writing of all holders of the outstanding Preferred Shares. If any such quorum is not present within half an hour after the time appointed for the meeting, then the meeting shall be adjourned to a date being not less than 15 days later and at such time and place as may be appointed by the chairman and at such meeting a quorum will consist of that number of shareholders present in person or represented by proxy. The formalities to be observed with respect to the giving of notice of any such meeting or adjourned meeting and the conduct thereof shall be those which may from time to time be prescribed in our by-laws with respect to meetings of shareholders. On every vote taken at every such meeting or adjourned meeting each holder of a Preferred Share shall be entitled to one vote in respect of each one dollar of stated value of Preferred Shares held.

Exchangeable Shares

Voting Rights: Holders of Exchangeable Shares are entitled to notice of, to attend at, and to that number of votes equal to the number of Exchangeable Shares held multiplied by the Exchange Ratio in effect at the meeting record date (rounded to the nearest whole number) at any meeting of our Shareholders (other than meeting of a class or series of our shares other than the Exchangeable Shares).

Exchange Rights: A holder of Exchangeable Shares has the right, at the holder's option, at any time to exchange, subject to the terms and provisions of the Exchangeable Shares, any Exchangeable Shares into fully paid and non-

assessable Common Shares on the basis of that number of Common Shares equal to the number of Exchangeable Shares multiplied by the Exchange Ratio in effect on the Notice Date (defined below).

The Exchange Ratio for the Exchangeable Shares was equal to 1.0000 as at January 1, 2011, and is cumulatively adjusted thereafter by increasing the Exchange Ratio on each dividend payment date after January 1, 2011 and before the time as of which the Exchange Ratio is calculated, by an amount, rounded to the nearest five decimal places, equal to the amount in accordance with the following formula:

$$= \frac{A \times B}{C}$$

Where A is the dividend, expressed as an amount per Common Share, paid on that dividend payment date, B is Exchange Ratio immediately prior to the Dividend Record Date and C is the volume weighted average trading price for the five trading days preceding the first business day following the dividend record date for such dividend.

Upon the surrender of any Exchangeable Shares for exchange in accordance with the terms of the Exchangeable Shares, we shall issue and deliver, or cause to be delivered to or upon the written order of the holder of the Exchangeable Shares so surrendered, a certificate or certificates issued in the name of, or in such name or names as may be directed by, such holder representing the number of Common Shares to which such holder is entitled. Such exchange shall be deemed to have been made at the close of business on the date such Exchangeable Shares shall have been surrendered or, if such day is not a business day, the next business day (the "**Notice Date**") for exchange, so that the rights of the holder of such Exchangeable Shares, as the holder thereof, shall cease at such time and the person or persons entitled to receive Common Shares upon such exchange shall be treated for all purposes as having become the holder or holders of record of such Common Shares at such time and such exchange shall be on the basis of the exchange ratio in effect on such business day.

No holder of Exchangeable Shares shall be entitled to and neither we nor our transfer agent shall deliver fractions of a Common Share. Where it would otherwise result in a holder of Exchangeable Shares receiving a fraction of a Common Share, such holder of Exchangeable Shares shall only be entitled to receive the next lowest whole number of Common Shares.

Compulsory Exchange: In accordance with the provisions of the Exchangeable Shares, we may require the exchange of that number of Exchangeable Shares as determined by our Board of Directors on the basis of the Exchange Ratio in effect on the date set by us (the "**Compulsory Exchange Date**").

On and after the applicable Compulsory Exchange Date, the holders of the Exchangeable Shares called for exchange shall cease to be holders of such Exchangeable Shares and shall not be entitled to exercise any of the rights of holders in respect thereof, other than: (i) the right to receive their proportionate part of the total Common Shares; and (ii) the right to receive any declared and unpaid dividends on such Common Share.

Ranking: The holders of Exchangeable Shares shall be entitled in the event of any liquidation, dissolution or winding-up of us, whether voluntary or involuntary, or any other distribution of our assets among our shareholders for the purpose of winding-up our affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of our shares ranking in priority to the Exchangeable Shares in respect of return of capital on dissolution, to share rateably, together with the holders of the Common Shares and shares of any other class of our shares ranking equally with the Exchangeable Shares in respect of return of capital on dissolution, in such of our assets as are available for distribution. For the purpose of calculating the sharing ratio with the Common Shares, the holders of Exchangeable Shares will be deemed to have exchanged their Exchangeable Shares in accordance with the exchange ratio in effect on the day prior to the commencement of any liquidation, dissolution or winding-up, whether voluntary or involuntary, or any other distribution of our assets among our shareholders for the purpose of winding-up our affairs. The holders of Exchangeable Shares shall not be entitled to receive dividends.

DIRECTORS AND OFFICERS

The name, municipality of residence, position and principal occupation for the prior five years, of each of our directors and officers are as follows:

<u>Name and Municipality of Residence</u>	<u>Position</u>	<u>Principal Occupation</u>
Keith A. MacPhail ⁽²⁾ Calgary, Alberta	Chairman and Chief Executive Officer	Our Chairman and Chief Executive Officer.
Ronald J. Poelzer ⁽³⁾ Calgary, Alberta	Executive Vice President and Vice Chairman	Our Executive Vice President and Vice Chairman.
Ian S. Brown ⁽¹⁾⁽³⁾⁽⁷⁾ Calgary, Alberta	Director	Independent Businessman.
Michael M. Kanovsky ⁽¹⁾⁽²⁾⁽⁴⁾⁽⁵⁾ Victoria, British Columbia	Director	President, Sky Energy Corporation (an energy investment corporation).
Harry L. Knutson ⁽³⁾⁽⁴⁾ Vancouver, British Columbia	Director	Chairman and Chief Executive Officer, Nova Bancorp. Group (investment advisors and merchant bankers).
Margaret A. McKenzie ⁽¹⁾⁽³⁾⁽⁷⁾ Calgary, Alberta	Director	Chief Financial Officer, Range Royalty Management Ltd., general partner of Range Royalty Limited Partnership (a private royalty partnership)
Christopher P. Slubicki ⁽²⁾⁽⁴⁾⁽⁷⁾ Calgary, Alberta	Director	President and Chief Executive Officer of OPTI Canada Inc. (a public heavy oil corporation).
Walter C. Yeates ⁽¹⁾⁽²⁾ Toronto, Ontario	Director	Independent Businessman.
Jason E. Shehar Calgary, Alberta	President and Chief Operating Officer	Our President and Chief Operating Officer
Glenn A. Hamilton ⁽⁷⁾ Calgary, Alberta	Senior Vice President and Chief Financial Officer	Our Senior Vice President and Chief Financial Officer.
Thomas J. Mullane Calgary, Alberta	Senior Vice President	Our Senior Vice President.
Johannes H. Thiessen Calgary, Alberta	Senior Vice President	Our Senior Vice President.
Scott H. Hanson Calgary, Alberta	Vice President, Production	Our Vice President, Production.
Orest G. Humeniuk Calgary, Alberta	Vice President, Land	Our Vice President, Land.
Bruce W. Jensen Calgary, Alberta	Vice President, Engineering	Our Vice President, Engineering.
Dean M. Kobelka Calgary, Alberta	Vice President, Finance	Our Vice President, Finance.
Wayne E. Merkel Calgary, Alberta	Vice President, Exploration	Our Vice President, Exploration.
Lynda J. Robinson ⁽⁷⁾ Calgary, Alberta	Vice President, Human Resources and Administration	Our Vice President, Human Resources and Administration.
Hank R. Spence Calgary, Alberta	Vice President, Operations	Our Vice President, Operations.
Grant A. Zawalsky Calgary, Alberta	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors).

Notes:

- (1) Member of audit committee.
- (2) Member of reserves committee.
- (3) Member of governance and nominating committee.

- (4) Member of compensation committee.
- (5) Lead director.
- (6) We do not have an executive committee.
- (7) Each of our directors and officers have held the positions set forth above or other positions with us (or with BPL) for the previous five years other than: (i) Margaret A. McKenzie who was Vice President, Finance and Chief Financial Officer of Profico Energy Management Ltd. from 2001 to 2006; (ii) Christopher P. Slubicki who was Vice Chairman of Scotia Waterous from July, 2005 to June, 2006. Prior thereto, managing director of Waterous & Co; (iii) Glenn A. Hamilton who was Vice President and Chief Financial Officer of NuVista since July 2, 2003 prior to re-joining us on June 1, 2006; (iv) Scott Hanson joined us in June 2002 as Production Engineer. Mr. Hanson was promoted to Production Manager in April 2007, and was promoted to his current position of Vice President Production in August 2009; and (v) Lynda J. Robinson who was Manager of Corporate Services of StarPoint Energy Trust since January 2005 prior to re-joining us in January of 2006;

As at March 21, 2011, our directors and officers, as a group, beneficially owned, or controlled or directed, directly or indirectly, 5,989,739 Common Shares or approximately 4.42% of the issued and outstanding Common Shares and 17,594,495 Exchangeable Shares or approximately 82.68% of the issued and outstanding Exchangeable Shares resulting in an approximate total average ownership of 15.12%.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

None of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer or was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Except as otherwise disclosed herein, none of our directors or executive officers (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to affect materially the control of us is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or 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, or has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder, other than Mr. Zawalsky who was a former director of Efficient Energy Resources Ltd. (a private electrical generation company) which agreed to the voluntary appointment of a receiver in 2005 and Mr. MacPhail who was formerly a director of The Resort at Copper Point Ltd. (a private real estate development company) which was placed in receivership in 2009.

None of our directors or executive officers (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of us to affect materially the control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. No assurances can be given that opportunities identified by such board members will be provided to us.

The *Business Corporations Act* (Alberta) provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under such Act. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of such Act.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of our Board of Directors is attached hereto as Appendix D.

Composition of the Audit Committee

The members of our Audit Committee are Mr. Ian Brown, Mr. Michael Kanovsky, Ms. Margaret McKenzie and Mr. Walter Yeates, each of whom are independent and financially literate. We have adopted the definition of "independence" as set out in Section 1.4 of National Instrument 52-110 – *Audit Committees*. The relevant education and experience of each Audit Committee member is outlined below:

Ian Brown:

Mr. Brown is a Chartered Accountant with extensive director, financial and capital markets experience. From 1995 to 2005 Mr. Brown was a Senior Managing Director of Raymond James Ltd. (formerly Goepel McDermid). Prior thereto Mr. Brown was the Executive Vice President of the Alberta Stock Exchange from 1986 to 1995. Prior thereto, Mr. Brown was in the practice of public accounting.

Mr. Brown joined the Board of Directors in May 2004.

Mr. Brown presently sits on several public and private boards, including, Cathedral Energy Services Ltd., Consolidated Westview Resources Ltd., Petrobank Energy and Resources Ltd., PetroBakken Energy Ltd., Sembiosys Genetics Inc. and the Canadian Investor Protection Fund. Mr. Brown also was a board member of the TSX Group from 2001 to 2006; a board member of Market Regulation Services Inc. from 2001 to 2005; and a board member and Vice Chairman of the Canadian Venture Exchange from 1999 to 2001.

Mr. Brown holds a Bachelor of Commerce degree from the University of Windsor and a Bachelor of Arts degree from McMaster University. Mr. Brown obtained his Chartered Accountants designation in 1983.

Michael Kanovsky:

Mr. Kanovsky has had significant experience in the oil and natural gas sector. In 1978, he co-founded Canadian Northstar Corporation and its successor, Northstar Energy Corporation, where he was primarily responsible for strategic development, finance and acquisitions until it was taken over by Devon Energy Corporation. Mr. Kanovsky continues today as a Director of Devon Energy Corporation. Mr. Kanovsky has also held positions such as Chairman of Taro Industries Limited, CEO of Arrowstar Drilling and Vice-Chairman of Precision Drilling Inc. In 1997, Mr. Kanovsky was instrumental in the reorganization of BPL and continues as an active director. He is also a director of ARC Resources Ltd., Argosy Energy Inc., TransAlta Inc. and Pure Technologies.

Mr. Kanovsky joined our Board of Directors in January 1997.

Mr. Kanovsky holds a Bachelor of Applied Science (Honours) degree in Mechanical Engineering from Queen's University and a Masters of Business Administration from the University of Western Ontario's Ivey School of Business and is a Professional Engineer.

Margaret A. McKenzie:

Ms. McKenzie is a Chartered Accountant with several years experience in the oil and natural gas industry. Ms. McKenzie is currently the Chief Financial Officer, Range Royalty Management Ltd. (general partner of Range Royalty Limited Partnership, a private royalty partnership). She was previously Vice President Finance and Chief Financial Officer of Profico Energy Management Ltd. (a private oil and gas company) and Manager, Treasury and Administration with Renaissance Energy Ltd. (a public oil and gas company).

Ms. McKenzie joined our Board of Directors in May 2006.

Ms. McKenzie is on the board of directors of Zargon Oil & Gas Ltd. and three private oil and natural gas exploration and development companies (Spur Resources Ltd., Endurance Energy Ltd. and Home Quarter Resources Ltd.).

Ms. McKenzie holds a Bachelor of Commerce with Distinction degree from the University of Saskatchewan and has been a member of the Institute of Chartered Accountants of Alberta since 1985.

Walter Yeates:

Mr. Yeates was a Director of UBS Warburg, investment banker, and was active in corporate finance, valuations and advisory services for several years. Prior to this, Mr. Yeates was a financial officer of Alberta Energy Company and Bow Valley Resource Services in Calgary, and Canada Development Corp., a large management holding company in Toronto. Mr. Yeates was a founding partner of a successful international inter-bank currency broker headquartered in New York City and was also on various private and public advisory boards.

Mr. Yeates joined our Board of Directors in July 2003.

Mr. Yeates holds a Masters of Business Administration degree from the University of Western Ontario's Ivey School of Business.

Pre-Approval of Policies and Procedures

Our Audit Committee must pre-approve all non-audit services to be provided to us and our subsidiary entities by the external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Audit Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Audit Committee from time to time.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditor in each of the last two fiscal years for audit services were \$432,500 in 2010 and \$401,500 in 2009.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance related services by our external auditor that are reasonably related to the performance of the audit or review of our financial statements that are not reported under "Audit Fees" above were \$75,000 in 2010 and nil in 2009.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by our external auditor for tax compliance, tax advice and tax planning were \$4,000 in 2010 and \$32,000 in 2009.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by our auditors other than services reported above were \$40,000 in 2010 and \$55,000 in 2009.

DIVIDENDS TO SHAREHOLDERS**Dividends and Dividend Policy**

Cash dividends are made on the 15th day (or if such date is not a business day, on the next business day) following the end of each calendar month to Shareholders of record on the last business day of each such calendar month or such other date as determined from time to time by us.

We carefully monitor the impact of all issues affecting our business and, the necessity to adjust our monthly dividends and our capital programs as conditions evolve. Dividends are normally announced on a quarterly basis in the context of prevailing and anticipated commodity prices. During periods of volatile commodity prices, we may vary the dividend rate monthly.

Our long term objective is to set a dividend policy at prudent levels while withholding sufficient funds to finance capital expenditures required to modestly grow our current production base. This in turn, is expected to provide a stronger base of cash flow leading to consistent and sustainable dividends into the future. Our dividend policy is reviewed monthly and is based on a number of factors including current and future commodity prices, foreign exchange rates, our commodity hedging program, current operations and available investment opportunities

Our Credit Facilities (as defined herein) contains restrictions on our ability to pay dividends in certain circumstances. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the *Business Corporations Act* (Alberta). Pursuant to the *Business Corporations Act* (Alberta), after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. As at December 31, 2010, our legal stated capital was \$1.0 billion.

Cash dividends are not guaranteed. Our historical cash dividends may not be reflective of future cash dividends, which will be subject to review by our Board of Directors taking into account our prevailing financial circumstances at the relevant time. Although we intend to make dividends of our available cash to Shareholders, these cash dividends may be reduced or suspended. The actual amount distributed will depend on numerous factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of solvency tests imposed by the ABCA for the declaration and payment of dividends applicable law and other factors beyond our control. See "Risk Factors".

The following monthly cash dividends on Common Shares were declared by us in 2011 in the following amounts:

<u>For the Month Ended</u>	<u>Dividends per Common Share</u>	<u>Payment Date</u>
January 31, 2011	\$0.12	February 15, 2011
February 28, 2011	\$0.12	March 15, 2011
March 31, 2011	\$0.12	April 15, 2011

These dividends were designated as "eligible dividends" for Canadian income tax purposes. Unless otherwise indicated, all dividends paid or to be paid by us are designated as "eligible dividends".

The following monthly cash distributions were declared by the Trust for each of the three most recently completed financial years:

For the Month Ended	Distributions per Trust Unit	Payment Date
January 31, 2008	\$0.30	February 15, 2008
February 29, 2008	\$0.30	March 17, 2008
March 31, 2008	\$0.30	April 15, 2008
April 30, 2008	\$0.30	May 15, 2008
May 31, 2008	\$0.30	June 16, 2008
June 30, 2008	\$0.30	July 15, 2008
July 31, 2008	\$0.30	August 15, 2008
August 31, 2008	\$0.30	September 15, 2008
September 30, 2008	\$0.30	October 15, 2008
October 31, 2008	\$0.30	November 17, 2008
November 30, 2008	\$0.30	December 15, 2008
December 31, 2008	\$0.30	January 15, 2009
Total	\$3.60	

For the Month Ended	Distributions per Trust Unit	Payment Date
January 31, 2009	\$0.20	February 16, 2009
February 28, 2009	\$0.20	March 16, 2009
March 31, 2009	\$0.16	April 15, 2009
April 30, 2009	\$0.16	May 15, 2009
May 31, 2009	\$0.16	June 15, 2009
June 30, 2009	\$0.16	July 15, 2009
July 31, 2009	\$0.16	August 17, 2009
August 31, 2009	\$0.16	September 15, 2009
September 30, 2009	\$0.16	October 15, 2009
October 31, 2009	\$0.16	November 16, 2009
November 30, 2009	\$0.16	December 15, 2009
December 31, 2009	\$0.16	January 15, 2010
Total	\$2.00	

For the Month Ended	Distributions per Trust Unit	Payment Date
January 31, 2010	\$0.16	February 15, 2010
February 28, 2010	\$0.16	March 15, 2010
March 31, 2010	\$0.16	April 15, 2010
April 30, 2010	\$0.16	May 17, 2010
May 31, 2010	\$0.16	June 15, 2010
June 30, 2010	\$0.16	July 15, 2010
July 31, 2010	\$0.16	August 16, 2010
August 31, 2010	\$0.16	September 15, 2010
September 30, 2010	\$0.16	October 15, 2010
October 31, 2010	\$0.16	November 15, 2010
November 30, 2010	\$0.16	December 15, 2010
December 31, 2010	\$0.16	January 17, 2011
Total	\$1.92	

MARKET FOR SECURITIES

Our Common Shares are listed and posted for trading on the Toronto Stock Exchange under the trading symbol "BNP". The Exchangeable Shares are not listed or posted for trading on any stock exchange.

The Common Shares commenced trading on the Toronto Stock Exchange on January 7, 2011 following completion of the Arrangement. The following table sets forth the high and low trading prices and the aggregate volume of trading of the Common Shares, as reported by the Toronto Stock Exchange for the periods indicated.

<u>Period</u>	<u>High</u>	<u>Low</u>	<u>Volume</u>
<u>2011</u>			
January (7 to 31)	\$29.97	\$25.12	11,332,331
February	\$32.00	\$29.34	13,154,143
March (1 to 25)	\$30.67	\$27.08	8,004,815

In connection with the Arrangement, holders of Trust Units and BPL Exchangeable Shares exchanged their Trust Units for Common Shares and their BPL Exchangeable Shares for Exchangeable Shares. Prior to the Arrangement, the Trust Units were listed and traded on the Toronto Stock Exchange. The trading symbol for the Trust Units was BNP.UN. The BPL Exchangeable Shares were not listed or posted for trading on any stock exchange.

The following table sets forth the high and low trading prices and the aggregate volume of trading of the Trust Units, as reported by the Toronto Stock Exchange in 2010 and up to January 6, 2011.

<u>Period</u>	<u>High</u>	<u>Low</u>	<u>Volume</u>
<u>2010</u>			
January	\$24.45	\$22.40	6,341,667
February	\$24.85	\$22.41	6,163,402
March	\$25.70	\$23.35	8,656,297
April	\$25.29	\$23.01	7,143,482
May	\$25.02	\$22.03	12,882,139
June	\$25.60	\$22.63	6,666,738
July	\$24.40	\$22.34	3,564,589
August	\$24.65	\$23.15	5,574,264
September	\$24.91	\$22.50	10,347,833
October	\$26.05	\$23.88	6,517,698
November	\$28.41	\$25.58	6,823,260
December	\$29.50	\$27.90	5,859,012
<u>2011</u>			
January (1 to 6)	\$29.47	\$28.79	1,334,725

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and natural gas industry. It is not expected that any of these regulations or controls will affect our operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production levels of oil and natural gas in western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA prohibits discriminatory border restrictions and export taxes. NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of

those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, well depth, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of \$3.50/ha, and make monthly royalty payments in respect of oil and natural gas produced.

On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010. Alberta royalties in effect after December 31, 2010 are known as the "Alberta Royalty Framework" ("**ARF**").

Under the ARF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Effective January 1, 2011, royalty rates for conventional oil range from 0-40%, depending on the vintage of the oil, with a rate cap of \$120/bbl. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than \$535/m³ compared to the previous royalty curve.

Royalty rates for natural gas under the ARF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the ARF is 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than \$5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the ARF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil and Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to \$55 and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at \$120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil

increase above \$55 up to 40% when oil is priced at \$120 or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and natural gas.

In April 2005, the Government of Alberta implemented the Innovative Energy Technologies Program (the "**IETP**"), which has the stated objectives of increasing recovery from oil and natural gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP is backed by a \$200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs intended to encourage the development of deeper, higher cost oil and natural gas reserves. A five-year program for conventional oil exploration wells over 2,000 m provides qualifying wells with up to a \$1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 m provides a sliding scale royalty credit based on depth of up to \$3,750/m. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 m, removing a supplemental benefit of \$875,000 for wells exceeding 4,000 m that are spud subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt the new transitional royalty rates Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers were only able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that had already elected to adopt such rates as of that date were permitted to switch to Alberta's conventional royalty structure up until February 15, 2011. On January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the ARF. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a \$200/m royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 bbls of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010;
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of \$3.50/ha, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to \$100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;
- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 m and horizontal wells

- with a true vertical depth greater than 2,300 m spud between December 1, 2003 and September 1, 2009;
- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 m and a re-entry date subsequent to December 1, 2003;
 - *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m³ of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 m whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;
 - *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m³ as well as a royalty credit for coalbed gas wells equal to \$50,000 for wells drilled on Crown land and a tax credit equal to \$30,000 for wells drilled on freehold land;
 - *Marginal Royalty Reduction Program* providing royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m³ during the first 12 production months and average daily production less than 23 m³ for every metre of marginal well depth;
 - *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 m, average monthly production under 60,000 m³ during the first 12 production months and average daily production less than 11.5 m³ (development wells) or 17 m³ (exploratory wildcat wells) for every 100 m of marginal well depth;
 - *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m³ of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and natural gas areas. In both 2009 and 2010, the Government of British Columbia allocated \$120 million in royalty credits for oil and natural gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 m. Wells spud between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An additional \$50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of \$100 per m³ for third and fourth tier oil and \$50 per m³ for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier natural gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old natural gas (not classified as either third tier, fourth tier or new natural gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier natural gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a natural gas-oil production ratio in any month of more than 3,500 m³ of natural gas for every m³ of oil, and new natural gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and natural gas concurrently without natural gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* which replaces the existing *Freehold Oil and Gas Production Tax Act* and is intended to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new Act.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of \$50 per thousand m³ for third and fourth tier natural gas and \$35 per thousand m³ for new natural gas and old natural gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier natural gas, 15% for third tier or new natural gas, and 20% for old natural gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier natural gas, 35% for third tier and new natural gas, and 45% for old natural gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m³ for deep development vertical oil wells, 4,000 m³ for non-deep exploratory vertical oil wells and 16,000 m³ for deep exploratory vertical oil wells (more than 1,700 m or within certain formations);
- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m³ for qualifying exploratory natural gas wells;
- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m³ for non-deep horizontal oil wells and 16,000 m³ for deep horizontal oil wells (more than 1,700 m or within certain formations);
- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout;
- *Royalty/Tax Regime for High Water-Cut Oil Wells* granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities; and
- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m³ for horizontal gas wells.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its GHG emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO₂ equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO₂ equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at \$15 per tonne of CO₂ equivalent for the 2010 to 2012 period, rising to \$20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 7 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark (the "**Copenhagen Conference**") resulted in the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. From November 29 to December 10, 2010, a meeting between representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

In response to the Copenhagen Accord, the Government of Canada indicated on January 29, 2010 that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which were discussed above.

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

On December 23, 2010, the United States Environmental Protection Agency indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by July, 2011 and for refineries by December, 2011.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed

their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of \$15 per tonne of CO₂ equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

We have a 5.3% working interest in a Balzac gas plant that meets the reporting requirements.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at \$10 per tonne of CO₂ equivalent and rose to \$15 per tonne of CO₂ equivalent on July 1, 2009 and \$20 per tonne of CO₂ equivalent on July 1, 2010. It is scheduled to further increase at a rate of \$5 per tonne of CO₂ equivalent on July 1 of every year until it reaches \$30 per tonne of CO₂ equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and will come into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. It is expected that GHG emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO₂ equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO₂ equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO₂ equivalents per year are required to have their emissions reports verified by a third party.

We have a working interest in two facilities in British Columbia that meet the reporting requirements. Neither of these facilities meet the reporting verification requirements.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on

May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

RISK FACTORS

An investment in our Shares is subject to various risks including those risks inherent to the industry in which we operate. If any of these risks occur, our production, revenues and financial condition could be materially harmed, with a resulting decrease in dividends on, and the market price of, the Common Shares. As a result, the trading price of our Common Shares could decline, and you could lose all or part of your investment. Cash dividends to Shareholders are not assured or guaranteed.

Before deciding whether to invest in any Shares, investors should consider carefully the risks set out below. If any of the risks described below materialize, our business, financial condition or results of operations could be materially and adversely affected. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect our business, financial condition or results of operations. Residents of the United States and other non-residents of Canada should have additional regard to the risk factors under the heading "*– Certain Risks for United States and other non-resident Shareholders*".

The information set forth below contains "forward-looking statements", which are qualified by the information contained in the section of this Annual Information Form entitled "*Notice to Reader – Special Note Regarding Forward-Looking Statements*".

Risks Relating to Our Business and Operations

Declines in oil and natural gas prices will adversely affect our financial condition

Our operational results and financial condition, and therefore the amounts we pay to Shareholders as dividends, will be dependent on the prices received for our oil and natural gas production. Oil and natural gas prices have exhibited extreme volatility over the past few years. Declines in oil and natural gas prices may result in declines in, or the elimination of, dividends to Shareholders.

Oil and natural gas prices are determined by economic factors and in the case of oil prices, political factors and a variety of additional factors beyond our control. These factors include economic conditions in the United States and Canada and worldwide, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, internal capacity to produce natural gas in the United States from shale deposits, weather conditions including weather-related disruptions to the North American natural gas supply, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our proved and probable reserves, net asset value, borrowing capacity, revenues, profitability and funds from operations and ultimately on our financial condition and therefore on the dividends to our Shareholders. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Variations in interest rates and foreign exchange rates could affect our financial condition

There is a risk that interest rates will increase given the current historical low level of interest rates. An increase in interest rates could result in a significant increase in the amount we pay to service debt and affect our ability to fund ongoing operations, resulting in a decrease in dividends to Shareholders, and could impact the market price of the Common Shares.

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canada/U.S. foreign exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our production revenue and our ability to maintain dividends to Shareholders in the future. Future Canada/U.S. foreign exchange rates could also impact the future value of our reserves as determined by our independent evaluators.

A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies in acquiring Canadian oil and natural gas properties and may make it more difficult for us to replace reserves through acquisitions.

Continued uncertainty in the credit markets may restrict the availability or increase the cost of borrowing required for future development and acquisitions

Continued uncertainty in domestic and international credit markets could materially affect our ability to access sufficient capital for our capital expenditures and acquisitions and, as a result, may have a material adverse effect on our ability to execute our business strategy and on our financial condition. There can be no assurance that financing will be available or sufficient to meet these requirements or for other corporate purposes or, if financing is available, that it will be on terms appropriate and acceptable to us. Should the lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued resulting in a dilutive effect on current and future Shareholders.

Our bank loan facility will need to be renewed prior to September 13, 2013 and failure to renew, in whole or in part, or higher interest charges will adversely affect our financial condition

We currently have a bank loan facility of \$1.0 billion with \$416.0 million of undrawn borrowing capacity, an uncommitted master shelf agreement that allows for a draw of up to US\$125 million in notes with \$75 million of undrawn capacity, and senior unsecured notes of US\$300 million and CDN\$50 million (collectively referred to as "**Credit Facilities**"). In the event that the bank loan facility is not extended before September 10, 2013, indebtedness under the bank loan facility will be repayable on September 10, 2013. The senior unsecured notes are repayable under various maturity dates with \$400 million of the notes repayable in 2015 and thereafter. Repayment of all outstanding amounts under the Credit Facilities may be demanded on relatively short notice if an event of default occurs. If this occurs, we may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on our business, and dividends to Shareholders may be materially reduced. There is also a risk that the Credit Facilities will not be renewed for the same amount or on the same terms.

Our existing Credit Facilities and any replacement Credit Facilities may not provide sufficient liquidity. The amounts available under our existing Credit Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all.

We are required to comply with covenants under the Credit Facilities. In the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required on an accelerated basis by our lenders, and the ability to pay dividends to our Shareholders may be restricted.

We have been historically reliant on external sources of capital, borrowings and equity sales and, if unavailable, our financial condition will be adversely affected

Amounts paid in respect of interest and principal on debt may reduce dividends to Shareholders. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of dividends. Certain covenants in the agreements with our lenders under the Credit Facilities may also limit dividends. Although we believe the Credit Facilities will be sufficient for our immediate requirements, there can be no assurance that the amount will be adequate for our future financial obligations including our future capital expenditure program, or that we will be able to obtain additional funds.

As future capital expenditures will be financed out of funds flow from operating activities, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and our securities in particular.

From time to time we may enter into transactions which may be financed in whole or in part with debt. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise. To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain or expand existing assets and reserves may be impaired, and our assets, liabilities, business, financial condition, results of operations and dividends to Shareholders may be materially and adversely affected as a result.

Shareholders may suffer dilution in connection with future issuances of Common Shares. In the normal course of making capital investments to maintain and expand our oil and natural gas reserves additional Shares or other securities may be issued. Additionally, from time to time we may issue Shares or other securities in order to finance significant acquisitions or development projects or to reduce debt and maintain a more optimal capital structure. Our success is, in part, dependent on our ability to raise capital from time to time by issuing additional Shares or other securities. Shareholders may suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of Common Shares issued to acquire those assets. Shareholders may also suffer dilution in connection with future issuances of Common Shares to complete acquisitions.

We believe that estimated funds from operations, together with the Credit Facilities, will be sufficient to substantially finance our current operations, dividends to Shareholders and planned capital expenditures for the ensuing year. The timing of most of our capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of dividends is also discretionary, and we have the ability to modify dividend levels should funds from operations be negatively impacted by a reduction in commodity prices or other factors. However, if funds from operations is lower than expected or capital costs for these projects exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing properties, we may be required to seek additional capital to maintain our capital expenditures at planned levels. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties or a decrease in dividends to Shareholders.

Our hedging activities may negatively impact our income and our financial condition

We may manage the risk associated with changes in commodity prices by entering into petroleum or natural gas price hedges. If we hedge our commodity price exposure, we may forego some of the benefits we would otherwise experience if commodity prices were to increase. As at December 31, 2010, our income statement reflected \$3.8 million of unrealized gains resulting from hedges to protect our commodity risk exposure. For more information in relation to our commodity hedging program, see "*Description of Our Business – Disclosure of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Forward Contracts*". We may initiate certain hedges to attempt to mitigate the risk of the Canadian dollar appreciating against the U.S. dollar. An increase in the Canada/U.S. foreign exchange rate will impact future dividends and the future value of our reserves as determined by independent evaluators. These hedging activities could expose us to losses and to credit risk associated with counterparties with which we contract.

Failure of third parties to meet their contractual obligations to us may have a material adverse affect on our financial condition

We are exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, third party operators, marketers of our petroleum and natural gas production, hedge counterparties and other parties. We manage this credit risk by entering into sales contracts with creditworthy entities and reviewing our exposure to individual entities on a regular basis. However, in the event such parties fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

Our ability to maintain dividends is dependent on a number of factors, including volatility of prices for oil and natural gas, interest rates, sources of capital, changes in legislation and those set forth below

Our ability to add to our petroleum and natural gas reserves is highly dependent on our success in exploiting existing properties and acquiring additional reserves. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce petroleum and natural gas reserves. Future oil and natural gas exploration may involve unprofitable efforts, not only from unsuccessful wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completion, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion, operating and other 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. New wells we drill or participate in may not become productive and we may not recover all or any portion of our investment in wells we drill or participate in. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project.

Higher operating costs for our underlying properties will directly decrease the amount of cash flow received by us and, therefore, may reduce dividends to Shareholders. Labour costs, electricity, gas processing, well servicing and chemicals are a few of our operating costs that are susceptible to material fluctuation. There is no assurance that further commercial quantities of petroleum and natural gas will be discovered or acquired by us.

The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in production could result in materially lower revenues and cash flow and, therefore, may reduce dividends to Shareholders.

There is no assurance we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserves additions, our reserves will deplete and as a consequence, either production from, or the average reserves life of, our properties will decline, which will result in a reduction in the value of Common Shares and in a reduction in funds from operations available for dividends to Shareholders.

Our business is heavily regulated and such regulation increases our costs and may adversely affect our financial condition

The oil and gas industry in Canada is subject to federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and sites (including restrictions on production) and possibly expropriation or cancellation of contract rights. Governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas and such regulations may be amended from time to time. Regulation increases our costs which will result in a reduction in funds from operations available for dividends to Shareholders.

In order to conduct oil and natural gas operations, we require licenses from various governmental authorities. There can be no assurance that we will be able to obtain all of the licenses and permits that may be required to conduct operations that we may wish to undertake. See "*Industry Conditions*".

Changes in government regulations that affect the oil and natural gas industry could adversely affect us and reduce our dividends to our Shareholders

Government regulations may change from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas or increase our costs, either of which would have a material adverse impact on us. See "*Industry Conditions*".

Income tax laws or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders

Changes in tax and other laws may adversely affect Shareholders. Income tax laws, other laws or government incentive programs relating to the oil and gas industry, such as resource allowance, may in the future be changed or interpreted in a manner that adversely affects the Corporation and Shareholders. Tax authorities having jurisdiction over the Corporation or the Shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of Shareholders.

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan all of which should be carefully considered by investors in the oil and natural gas industry. All of such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse and there can be no assurance that there will not be further revocation, amendment or administrative change which will be materially adverse to our assets, reserves, financial condition or results of operations or prospects and our ability to maintain dividends to Shareholders.

We cannot assure you that income tax laws and government incentive programs relating to the oil and natural gas industry generally will not change in a manner that adversely affects the market price of the Common Shares.

There are numerous uncertainties inherent in estimating quantities of recoverable petroleum and natural gas reserves, including many factors beyond our control

Although we, together with GLJ and Ryder Scott, have carefully prepared the reserves figures included in this Annual Information Form and believe that the methods of estimating reserves have been verified by operating experience, such figures are estimates and no assurance can be given that the indicated levels of reserves will be produced.

In general, estimates of economically recoverable petroleum and natural gas reserves and resources and the future net revenues 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 petroleum and natural 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 based on professional judgment and classifications of reserves, which, by their nature have a high degree of subjectivity. For those reasons, estimates of the economically recoverable petroleum and natural gas reserves or estimates of resources 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 reserves and recovery information contained in the Reserves Report is only an estimate and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by GLJ and Ryder Scott and such variations could be material. The Reserves Report has been prepared using certain commodity price assumptions which are described in the notes to the reserves tables. If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the price assumptions utilized in the Reserves Report,

the present value of estimated future net revenues for our reserves and our net asset value would be reduced and the reduction could be significant. The estimates in the Reserves Report are based in part on the timing and success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the Reserves Report will be reduced, in future years, to the extent that such activities do not achieve the level of success assumed in the Reserves Report.

Estimates of proved undeveloped reserves are sometimes 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.

Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome

These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, equipment failures and other accidents, sour gas releases and spills, uncontrollable flows of oil, natural gas or well fluids, the invasion of water into producing formations, adverse weather conditions, pollution, other environmental risks, fires, spills and delays in payments between parties caused by operation or economic matters which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment, personal injuries, loss of life and other hazards, all of which could result in liability. These risks will increase as we undertake more exploratory activity. Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks nor are all such risks insurable and in certain circumstances we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. In addition, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect upon our financial condition.

Exploration and development risks arise due to the uncertain results of searching for and producing petroleum and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploration efforts in areas in which we have existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods and controlling costs to maximize returns.

Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations, prospects and our ability to maintain dividends to Shareholders.

The operation of a portion of our properties is largely dependent on the ability of third party operators, and harm to their business could cause delays and additional expenses in our receiving revenues

The continuing production from a property, and to some extent the marketing of production, is dependent upon the ability of the operators of our properties. Approximately 15.3 percent of our properties are operated by third parties, based on daily production. If, in situations where we are not the operator, the operator fails to perform these functions properly or becomes insolvent, revenues may be reduced. Revenues from production generally flow through the operator and, where we are not the operator, there is a risk of delay and additional expense in receiving such revenues.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the properties, and by the operator to our operating entities, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of properties or the establishment by the operator of reserves for such expenses. Our return on assets operated by others therefore will depend upon a number of factors that may be outside of our 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. Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects and our ability to maintain dividends to Shareholders.

Delays in business operations could adversely affect dividends to Shareholders and the market price of the Common Shares

Delays in business operations could adversely affect dividends to Shareholders and the market price of our Common Shares. In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- restrictions due to limited pipeline capacity;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of cash available for dividends to Shareholders in a given period and expose us to additional third party credit risks.

The marketability of petroleum and natural gas that may be acquired or discovered by us will be affected by numerous factors beyond our control

These factors include demand for petroleum and natural gas, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulations, including regulations relating to environmental protection, royalties, allowable production, pricing, importing and exporting of oil and natural gas and political events throughout the world that cause disruptions in the supply of oil. Any particular event could result in a material decline in prices and therefore result in a reduction of our net production revenue. The availability of markets is beyond our control. In addition, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on our financial condition. We do not have insurance to protect against the risk from terrorism.

Climate change laws and related environmental, health and safety regulation may impose restrictions or costs on our business which may adversely affect our financial condition and our ability to maintain dividends

Nearly all aspects of our operations are subject to environmental, health and safety 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. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of us or our properties, some of which may be material. We may also be exposed to civil liability for environmental matters or for the conduct of third parties, including private parties commencing actions and new theories of liability, regardless of negligence or fault. Furthermore, management believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions or emissions intensity, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which we cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets. For more information on the evolution and status of climate change and related environmental legislation, see "*Industry Conditions – Climate Change Regulation*".

There has been much public debate with respect to the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies by either the provinces in which we operate our business or by the Government of Canada, and whether to meet international agreed limits, or as

otherwise determined, for reducing greenhouse gases could have a material impact on the nature of oil and natural gas operations, including ours. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on us and our operations and financial condition. Although we provide for the necessary amounts in our annual capital budget to fund our currently estimated environmental and reclamation obligations, there can be no assurance that we will be able to satisfy our actual future environmental and reclamation obligations from such funds.

Although we believe that we are in material compliance with current applicable environmental, health and safety regulations, no assurance can be given that such regulations will not result in a curtailment of production, a reduction of product demand, a material increase in the costs of production, development or exploration activities or otherwise adversely affect our business, financial condition, results of operations or prospects. Future changes in other environmental, health and safety legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition or results of operations and prospects. See "*Industry Conditions – Environmental Regulation*".

We may not be able to realize the anticipated benefits of acquisitions and dispositions or to manage growth

We make acquisitions and dispositions of businesses and assets in the ordinary course of our business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with our operations. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. There is no assurance that we will be able to continue to complete acquisitions or dispositions of oil and natural gas properties which realize all the synergistic benefits.

We periodically dispose of non-core assets so that management can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, could be expected to realize less than their carrying value on our financial statements.

The price we pay for the purchase of any material properties is based on several criteria, including engineering and economic assessments made by independent engineers modified to reflect our technical and economic views. These assessments include a series of assumptions regarding such factors as recoverability and marketability of petroleum and natural gas, future prices of petroleum and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic and engineering uncertainty which could result in lower than anticipated production and reserves. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flow from operating activities and dividends to Shareholders.

We may be subject to growth-related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth could have a material adverse effect on our business, financial condition, results of operations and prospects.

There is strong competition relating to all aspects of the oil and gas industry

There are numerous companies in the oil and gas industry, who are competing with us for the acquisitions of properties with longer life reserves, properties with exploitation and development opportunities and undeveloped land. As a result of such competition, it may be more difficult for us to acquire reserves on beneficial terms. Many of these other organizations have significantly greater technical, financial and operational resources than us.

We compete with other oil and gas companies to hire and retain skilled personnel necessary for running our daily operations, including planning, capitalizing on available technical advances and the execution of our exploration and development program. The inability to hire and retain skilled personnel could adversely impact certain of our operational and financial results.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and completion and the related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. The substantial increase in horizontal drilling and the use of multi-stage fracturing equipment has placed increased demands on this specialized equipment. Demand for such limited equipment or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities.

Changes to accounting policies, including the implementation of IFRS, may result in significant adjustments to our financial results, which could negatively impact our business, including increasing the risk of failing a financial covenant contained within our Credit Facilities

In January 2006, the CICA Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, the AcSB confirmed in February 2008 that IFRS will replace Canadian GAAP in 2011 for Canadian publicly accountable enterprises. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences that must be evaluated. The implementation of IFRS may result in significant adjustments to our financial results, which could negatively impact our business, including increasing the risk of failing a financial covenant contained within our Credit Facilities. At this time, we cannot reasonably quantify the full impact that adopting IFRS will have on our financial position and future results. For information regarding the impact that IFRS will have on our accounting policies and financial statements, see "*International Financial Reporting Standards*" in our 2010 Management's Discussion and Analysis, which has been filed on SEDAR at www.sedar.com.

Our petroleum and natural gas reserves are a depleting resource and decline as such reserves are produced

Absent commodity price increases or cost effective acquisition and development activities, our funds from operations will decline over time in a manner consistent with declining production from typical petroleum and natural gas reserves. Our future petroleum and natural gas reserves and production, and therefore our funds from operations, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, our reserves and production may decline over time as reserves are produced.

We also distribute a significant proportion of our funds from operations to Shareholders rather than reinvesting it in reserves additions. Accordingly, if external sources of capital, including the issuance of additional Common Shares, become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our petroleum and natural gas reserves may be impaired. To the extent that we use funds from operations to finance capital expenditures or property acquisitions, the level of funds from operations available for distribution to Shareholders will be reduced. There can be no assurance that we will be successful in developing or acquiring additional reserves on terms that meet our investment objectives.

We may participate in larger projects and may have more concentrated risk in certain areas of our operations

We manage a variety of small and large projects in the conduct of our business. Project delays may impact expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

- 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 regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we 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 we produce.

We only operate in western Canada and the United States and expansion outside of these areas may increase our risk exposure

Our operations and expertise are currently primarily focused on oil and natural gas production and development in the Western Canadian Sedimentary Basin and the United States. In the future, we may acquire oil and natural gas properties outside of these geographic areas. In addition, we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines, or an interest in an oil sands project. Expansion of our activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors which may adversely affect our business, financial condition or results of operations.

Our success depends in large measure on the activities of our key personnel

Our Shareholders are entirely dependent on our management with respect to the acquisition of oil and natural gas properties, the development and acquisition of additional reserves, the management and administration of all matters relating to our properties, including the safekeeping of our primary workspace and computer systems. The loss of the services of key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. The contributions of the existing management team to our immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Securing and maintaining title to our properties is subject to certain risks

Our properties are held in the form of licenses and leases and working interests in licenses and leases. If we 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. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of a license or lease or the working interest relating to a license or lease may have a material adverse affect on our results of operations and business. In addition title to the properties can become subject to dispute and defeat our claim to title over certain of our properties.

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada and have also made claims that certain developments, including oil and natural gas exploration and development, may have been proceeding without the Crown carrying out appropriate consultations in the course of allowing such developments to proceed. We are not aware of any material claims having been made in respect of our properties and assets; however, if a claim arose and was successful this may have a material adverse affect on our results of operations and business.

Although title reviews are conducted prior to any significant purchase of assets, such reviews cannot guarantee that an unforeseen defect in the chain of title will not arise to defeat our title to certain assets. Such defects could reduce the amount of funds from operations, possibly resulting in lower dividends to our Shareholders which could result in a lower market price of the Common Shares.

We are affected by seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. 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. Also, 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. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for crude oil and natural gas.

Our permitted investments may be risky

An investment in us should be made with the understanding that the value of any of our investments may fluctuate in accordance with changes in the financial condition of such investments, the value of similar securities, and other factors. For example, the prices of Canadian government securities, bankers' acceptances and commercial paper react to economic developments and changes in interest rates. Commercial paper is also subject to issuer credit risk. Investments in energy-related companies and partnerships will be subject to the general risks of investing in equity securities. These include the risk that the financial condition of issuers may become impaired, or that the energy sector may suffer a market downturn. Securities markets in general are affected by a variety of factors, including governmental, environmental and regulatory policies, inflation and interest rates, economic cycles, and global, regional and national events. The value of our Common Shares could be affected by adverse changes in the market values of such investments.

Risks Relating to Ownership of Common Shares***Our Board of Directors has discretion in the payment of dividends and may choose not to maintain dividends in certain circumstances***

The amount of future cash dividends, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of our Board of Directors and management team, we will change our dividend policy from time to time and, as a result, future cash dividends could be reduced or suspended entirely. The market value of the Common Shares may deteriorate if we reduce or suspend the amount of the cash dividends that we pay in the future and such deterioration may be material. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of our dividends and potential legislative and regulatory changes.

Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and the decision by us to finance capital expenditures using funds from operations. A reduction in dividends could also negatively affect the market price of the Common Shares.

Production and development costs incurred with respect to properties, including power costs and the costs of injection fluids associated with tertiary recovery operations, reduce the income that we receive and, consequently, the amounts we can distribute to our Shareholders.

The timing and amount of capital expenditures will directly affect the amount of income available for dividends to our Shareholders. Dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are planned. To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that we are required to use funds from operations to finance capital expenditures or property acquisitions, the cash we receive will be reduced, resulting in reductions to the amount of cash we are able to distribute to our

Shareholders. A reduction in the amount of cash distributed to Shareholders may negatively affect the market price of the Common Shares.

Changes in market-based factors may adversely affect the trading price of the Common Shares

The market price of our Common Shares is sensitive to a variety of market based factors including, but not limited to, interest rates, foreign exchange rates and the comparability of the Common Shares to other yield-oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

Certain Risks for United States and other non-resident Shareholders

The ability of investors resident in the United States to enforce civil remedies is limited

We are a corporation incorporated under the laws of the Province of Alberta, Canada and our principal office is located in Calgary, Alberta. All of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all or a substantial portion of our assets and the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgements of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgements of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties); however, we also follow the United States practice of separately reporting reserve volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves; whereas the SEC rules require that a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, be utilized.

We included in this Annual Information Form estimates of proved and proved plus probable reserves. Probable reserves have a lower certainty of recovery than proved reserves. The SEC requires oil and natural gas issuers in their filings with the SEC to disclose only proved reserves but permits the optional disclosure of probable reserves. The SEC definitions of proved reserves and probable reserves are different than NI 51-101; therefore, proved, probable and proved plus probable reserves disclosed in this Annual Information Form may not be comparable to United States standards.

As a consequence of the foregoing, our reserve estimates and production volumes in this Annual Information Form may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

There is additional taxation applicable to non-residents

The Tax Act imposes a withholding tax at the rate of 25% on the dividends or other property paid by us to Shareholders who are non-residents of Canada, unless the rate is reduced under the provisions of a tax treaty

between Canada and the non-resident Shareholder's jurisdiction of residence. These taxes may change from time to time. Where the non-resident Shareholder is a United States resident entitled to benefits under the Canada-United States Income Tax Convention, 1980 and is the beneficial owner of the dividends, the rate of Canadian withholding tax applicable to dividends is generally reduced to 15%. Additionally, the reduced rates of taxation on qualified dividend income under current U.S. tax laws are scheduled to expire at the end of 2012 and there is no assurance that the reduced tax rates will be re-enacted in the future.

There is a foreign exchange risk for non-resident Shareholders

Our dividends are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to their home currency.

MATERIAL CONTRACTS

The only contracts to which we are a party, that can reasonably be regarded as material to a proposed investor in the Common Shares, other than contracts entered into in the ordinary course of business, are the following:

- (a) the Restricted Common Share Incentive Plan;
- (b) the Common Share Rights Incentive Plan;
- (c) the 2011 Restricted Share Award Incentive Plan;
- (d) the 2011 Stock Option Plan;
- (e) the credit agreement with respect to the bank facilities provided by a syndicate of chartered banks, which agreement is described in note 7 to our consolidated financial statements for the year ended December 31, 2010; and
- (f) the note indenture creating the unsecured subordinated notes, as described in note 7 and the notes issued not subject to a master shelf agreement as described in note 7 to our consolidated financial statements for the year ended December 31, 2010.

Copies of these agreements have been filed on SEDAR at www.sedar.com.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we are or was a party to, or that any of our property is or was the subject of, during the most recently completed financial year, that were or are material to us, and there are no such material legal proceedings that we are currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority during our most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into with a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares and Exchangeable Shares is Valiant Trust Company at its principal offices in Calgary, Alberta and Toronto, Ontario.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of any of our senior officers and directors, nominees for directors, any Shareholder who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the Common Shares or Exchangeable Shares or any known associate or affiliate of such persons in any transaction in the last three years or in any proposed transaction which has materially affected or is reasonably expected to materially affect us other than as disclosed herein or as otherwise publicly disclosed.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement, report or valuation made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than GLJ and Ryder Scott, our independent engineering evaluators, and KPMG LLP, our independent auditors.

None of the designated professionals of GLJ or Ryder Scott have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the report, valuation, statement or opinion prepared by it, at any time thereafter or to be received by them. KPMG LLP, Chartered Accountants, Bonavista's auditors, are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of us or of any of our associate or affiliate entities, except for Grant A. Zawalsky, our Corporate Secretary, is a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on SEDAR at www.sedar.com and on our website at www.bonavistaenergy.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans are contained in our information circular - proxy statement dated March 18, 2010 and will be contained in our 2011 proxy materials relating to our annual shareholders meeting to be held on May 5, 2011. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2010 and the related management's discussion and analysis.

For additional copies of the Annual Information Form and the materials listed in the preceding paragraphs please contact:

Bonavista Energy Corporation
1500, 525 – 8th Avenue SW
Calgary AB T2P 1G1
Tel: (403) 213-4300
Fax: (403) 262-5184

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION Form 51-101F3

Management of Bonavista Energy Corporation ("**Bonavista**") is responsible for the preparation and disclosure of information with respect to the Bonavista's oil and natural 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, 2010, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated Bonavista's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of Bonavista, has:

- (a) reviewed Bonavista's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors of Bonavista has reviewed Bonavista's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved

- (a) the content and filing with securities regulatory authorities of Form 51-101F2 containing reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator 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.

(signed) "*Keith A. MacPhail*"
Keith A. MacPhail
Chairman and Chief Executive Officer

(signed) "*Bruce W. Jensen*"
Bruce W. Jensen
Vice President, Engineering

(signed) "*Walter C. Yeates*"
Walter C. Yeates
Director, Chairman of Reserves Committee

(signed) "*Michael M. Kanovsky*"
Michael M. Kanovsky
Director, Member of Reserves Committee

March 2, 2011

**APPENDIX B
GLJ PETROLEUM CONSULTANTS LTD.**

**REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR
Form 51-101F2**

To the Board of Directors of Bonavista Energy Corporation ("**Bonavista**"):

1. We have evaluated Bonavista's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.
2. The reserves data are the responsibility of Bonavista'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 Bonavista evaluated by us for the year ended December 31, 2010, and identifies the respective portions thereof that we have evaluated and reported on to the Board of Directors of Bonavista:

<u>Independent Qualified Reserves Evaluator</u>	<u>Description and Preparation Date of Evaluation Report</u>	<u>Location of Reserves (County or Foreign Geographic Area)</u>	<u>Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - \$000s)</u>			
			<u>Audited</u>	<u>Evaluated</u>	<u>Reviewed</u>	<u>Total</u>
GLJ Petroleum Consultants Ltd.	Corporate Summary February 23, 2011	Canada	-	3,395,132	741,924	4,137,056

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.
6. We have no responsibility to update our reports 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:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 25, 2011

(signed) "*John Stilling*"
John Stilling, P. Eng.
Vice President

**APPENDIX C
RYDER SCOTT COMPANY**

**REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR
Form 51-101F2**

To the Board of Directors of Bonavista Energy Corporation ("**Bonavista**"):

1. We have evaluated Bonavista's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.
2. The reserves data are the responsibility of Bonavista'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 Bonavista evaluated by us for the year ended December 31, 2010, and identifies the respective portions thereof that we have evaluated and reported on to the Board of Directors of Bonavista:

<u>Independent Qualified Reserves Evaluator</u>	<u>Description and Preparation Date of Evaluation Report</u>	<u>Location of Reserves (County or Foreign Geographic Area)</u>	<u>Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - \$000s)</u>			
			<u>Audited</u>	<u>Evaluated</u>	<u>Reviewed</u>	<u>Total</u>
Ryder Scott Company	Estimate of Reserves and Future Income Report prepared December 31, 2010	Canada	-	388,038	-	388,038

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 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:

Ryder Scott Company, Calgary, Alberta, Canada, February 11, 2011

(signed) "*Alan T. Frison*"
Alan T. Frison, P. Eng.
Senior Vice President

APPENDIX D

MANDATE & TERMS OF REFERENCE OF THE AUDIT COMMITTEE BONAVISTA ENERGY CORPORATION

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Bonavista Energy Corporation ("**Bonavista**") to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board approval, the audited financial statements and other mandatory disclosure releases containing financial information and review the Report of the Reserve Committee of the annual reserves. The objectives of the Committee, with respect to Bonavista, the other subsidiaries, partnerships, trusts and other controlled entities of Bonavista, are as follows:

- To assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Bonavista and related matters;
- To provide better communication between directors and external auditors;
- To enhance the external auditor's independence;
- To increase the credibility and objectivity of financial reports; and
- To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

- The Committee shall be comprised of at least 3 directors of Bonavista, all of whom are "independent" (as such term is used in Multilateral Instrument 52-110 – Audit Committee ("**MI 52-110**").
- The Board shall have the power to appoint the Committee Chairman and other members of the committee.
- All of the members of the Committee shall be "financially literate". The Board has adopted the definition for "financial literacy" used in MI 52-110.

Meetings

- At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote.
- A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board.
- Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.
- The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board.
- The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year end financial statements) and at such other times as the external auditor and the audit Committee consider appropriate.

Mandate and Responsibilities of Committee

- It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.
- It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to Bonavista's Internal Control Systems:
 - identifying, monitoring and mitigating business risks; and
 - ensuring compliance with legal, ethical and regulatory requirements including the certification process.
- It is a primary responsibility of the Committee to review the annual financial statements of Bonavista prior to their submission to the Board for approval. The process should include but not be limited to:
 - review the appropriateness of significant accounting principles and any changes in accounting principles, or in their application, which may have a material impact on the current or future years' quarterly unaudited and annual audited financial statements;
 - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
 - reviewing accounting treatment of unusual or non-recurring transactions;
 - ascertaining compliance with covenants under loan agreements;
 - reviewing adequacy of the asset retirement obligation in the financial statements;
 - reviewing disclosure requirements for commitments and contingencies;
 - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
 - reviewing unresolved differences between management and the external auditors;
 - reviewing non-recurring transactions;
 - reviewing related party transactions; and
 - obtain explanations of significant variances with comparative reporting periods.
- The Committee is to review the financial statements, prospectuses, management discussion and analysis (MD&A), annual information forms (AIF) and all public disclosure containing audited or unaudited financial information before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Bonavista's disclosure of all other financial information and shall periodically access the accuracy of those procedures.

- With respect to the appointment of external auditors by the Board, the Committee shall:
 - recommend to the Board the appointment of external auditors;
 - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and confirmation that the external auditors shall report directly to the Committee;
 - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
 - review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors.
- Review with external auditors (and internal auditor if one is appointed by Bonavista) their assessment of the internal controls of Bonavista, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Bonavista and its subsidiaries.
- The Committee must pre-approve all non-audit services to be provided to Bonavista or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.
- The Committee shall review and monitor risk management policies and procedures of Bonavista including without limitation; the Enterprise Risk Assessment, hedging policies, litigation matters, insurance program, and report to the Board of Directors with respect to the risk assessment process and the appropriateness of risk management policies and procedures in managing risk.
- The Committee shall establish a procedure for:
 - the receipt, retention and treatment of complaints received by Bonavista regarding accounting, internal accounting controls or auditing matters; and
 - the confidential, anonymous submission by employees of Bonavista of concerns regarding questionable accounting or auditing matters.
- The Committee shall have the authority to investigate any financial activity of Bonavista. All employees of Bonavista are to cooperate as requested by the Committee.
- The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of Bonavista without any further approval of the Board.
- The Committee shall meet periodically with the external auditors, independent of management. The issues for consideration should include, but are not limited to:
 - obtain feedback on competencies, skill sets and performance of key members of the financial reporting team;
 - enquire as to significant differences from prior year period audits or reviews;
 - enquire as to transactions accounted for in an acceptable manner but not a basis which, in the opinion of the external auditor, was not the preferable accounting treatment;

- enquire as to any differences between management and the external auditor;
- enquire as to material differences in accounting policies, disclosures or presentation from prior periods;
- enquire as to deficiencies in internal controls identified in the course of the performance of the procedures by the external auditors;
- enquire as to any other matters or observations that the external auditors would like to bring to the attention of the committee.