ZARGON OIL & GAS LTD.

2011 ANNUAL INFORMATION FORM

March 12, 2012

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GLOSSARY OF SELECTED TERMS

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

Entities

Board of Directors means our board of directors.

Churchill means Churchill Energy Inc.

Exchangeable Shareholders means holders of Exchangeable Shares.

Masters means Masters Energy Inc.

Newco means 1563101 Alberta Ltd.

Oakmont means Oakmont Energy Ltd.

Old Zargon means Zargon Oil & Gas Ltd., prior to completion of the Arrangement.

Shareholders means holders of Common Shares.

TSX means Toronto Stock Exchange.

Trust means Zargon Energy Trust.

Unitholders means holders of Trust Units.

Zargon, **we**, **us** or **our** means Zargon Oil & Gas Ltd. and 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.

ZEC means 1563101 Alberta Ltd.

ZEI means Zargon ExchangeCo Inc.

ZEL means Zargon Energy Ltd.

Independent Engineering

COGE Handbook means the 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.

McDaniel means McDaniel & Associates Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

McDaniel Report means the report prepared by McDaniel dated February 15, 2012 evaluating the crude oil, natural gas and natural gas liquids reserves attributable to our oil and natural gas assets at December 31, 2011.

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

Securities and Other Terms

Arrangement means the arrangement among the Trust, Old Zargon, Newco, ZEI, Oakmont, ZEL, Zargon Acquisition Corp., Zargon Oil & Gas Partnership, the holders of Trust Units and the holders of 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.

Credit Agreement means the credit agreement dated June 28, 2011 as amended, which is described in note 11 to our consolidated financial statements for the year ended December 31, 2011, which is incorporated herein by reference.

Common Shares means our issued and outstanding common shares.

Exchangeable Shares means exchangeable shares of Old Zargon.

SEC means the United States Securities and Exchange Commission.

Shareholders means holders of Common Shares.

Trust Unit means trust units of the Trust.

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
bbl/d	barrels per day
Mbbl	thousand barrels
MMbbl	million barrels
NGLs	natural gas liquids

Natural Gas

gj	gigajoule
Mcf	thousand cubic feet
MMcf	million cubic feet
bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units

Other

ASP	means alkaline surfactant polymer
BOE or boe	means barrel of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent
Mmboe	million barrels of oil equivalent
Psi	pounds per square inch.
WTI	West Texas Intermediate.
°API	the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
$000s	thousands of dollars

CONVERSION

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

To Convert From	To	Multiply By
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	0.948
MMbtu	gigajoules	1.0551

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's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.**

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated.

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 (including the negative thereof). In addition, there are forward-looking statements in this Annual Information Form under the headings: "*Description of Our Business"* relating to our business plan and strategy, including our plans to high-grade our property footprint, and concentrate on cost containment initiatives, including the sale of non-strategic oil properties and cost saving opportunities relating to our natural gas properties; and our future capital expenditures; "*Description of Our Business – Disclosures of Reserves Data and Other Oil and Gas Information*" as to our reserves, future net revenues from our reserves and the anticipated after-tax value of such revenues, pricing and inflation and exchange rates, future development costs and the sources of funding of our future development costs; the development of our proved undeveloped reserves and probable undeveloped reserves; "*Description of Our Business – Disclosures of Reserves Data and Other Oil and Gas Information*" as to our future development activities and the results therefrom, land expiries, hedging policies, reclamation and abandonment obligations, tax horizon, production estimates, exploration and development activities, including our Little Bow ASP project development plans and the associated anticipated capital expenditures, anticipated finding and developments costs and field netbacks.. This information involves 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 information. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including such as those relating to results of operations and financial condition, general economic conditions, industry conditions, changes in regulatory and taxation regimes, volatility of commodity prices, escalation of operating and capital costs, regulatory approvals required in connection with our Little Bow ASP project, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel. Such forward-looking information is provided for the purpose of providing information about management's current expectations and plans relating to the future to allow investors to have a greater understanding of the Corporation's business. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions.

You are cautioned that the assumptions, including among other things, future oil and natural gas prices; future capital expenditures levels; future production levels; future exchange rates; the cost of developing and expanding our assets; our ability to obtain equipment in a timely manner to carry out development activities; our ability to market our oil and natural gas successfully to current and new customers; the impact of increasing competition; our ability to obtain financing on acceptable terms; and our ability to add production and reserves through our development and acquisition activities used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance, or achievement could differ materially from those expressed in, or implied by, these forward-looking statements. We can give no assurance that any of the events anticipated will transpire or occur, or if any of them do, what benefits we will derive from them. The forward-looking information contained in this document is expressly qualified by this cautionary statement. Our policy for updating forward-looking statements is that we disclaim, expect as required by law, any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

We believe the expectations reflected in these 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 to the forward-looking statements identified above, this Annual Information Form, and the documents incorporated by reference, contains forward-looking statements pertaining to the following:

- our business plan and strategy;
- the performance characteristics of our oil and natural gas properties;
- oil and natural gas production levels;
- drilling, completion and workover activities;
- expectations for facility modifications;
- seismic and exploration costs;
- projections of market prices and costs and the related sensitivities of dividends;
- supply and demand for oil and natural gas;
- 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;
- our dividend policy and payment of dividends;
- our capital expenditures programs;
- the sources of funding of our capital expenditures and future acquisitions.

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 set forth below and elsewhere in this Annual Information Form, 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 global economy and 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; borrowings and equity sales;
- risks associated with our hedging activities;
- geological, technical, drilling and processing problems;
- third party 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 acquiring, developing and exploring for natural gas and other aspects of our operations;
- risks associated with the marketability of oil and natural gas;
- changes in climate change laws and other environmental regulations;
- risks associated with the exploitation of our properties and our ability to acquire reserves;
- the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth;
- competition in the oil and natural gas industry;
- depletion of our reserves;
- risks associated with large projects or expansion of our activities;
- risks associated with retention of key personnel;
- risks associated with securing and maintaining our properties;
- seasonality; and
- risks associated with the timing of payment of dividends.

In addition, statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the 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 applicable law.

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 700, 333 – 5th Avenue S.W., Calgary, Alberta, T2P 3B6.

ZARGON OIL & GAS LTD.

General

We continued as "Zargon Oil & Gas Ltd." upon the amalgamation of Old Zargon, Newco, ZAC, ZEI and Oakmont on January 1, 2011 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 Exchangeable Shares were exchanged for common shares of Newco on the basis of 1.84716 common shares of Newco for each outstanding Exchangeable Share, and Newco acquired all of the assets and assumed all of the liabilities of the Trust; and (ii) on January 1, 2011, the Trust was dissolved and Old Zargon, Newco, ZAC, ZEI and Oakmont amalgamated. Following the Arrangement, we, together with our subsidiaries, owned, directly or indirectly, the same assets that were owned by the Trust and its subsidiaries immediately prior to the Arrangement. The Arrangement has been accounted for as a continuity of interests and, unless otherwise indicated, all information presented for the pre-Arrangement period in this Annual Information Form relates to the Trust.

Our registered, head and principal office is located at Suite 700, 333 – 5th Avenue S.W., Calgary, Alberta, T2P 3B6.

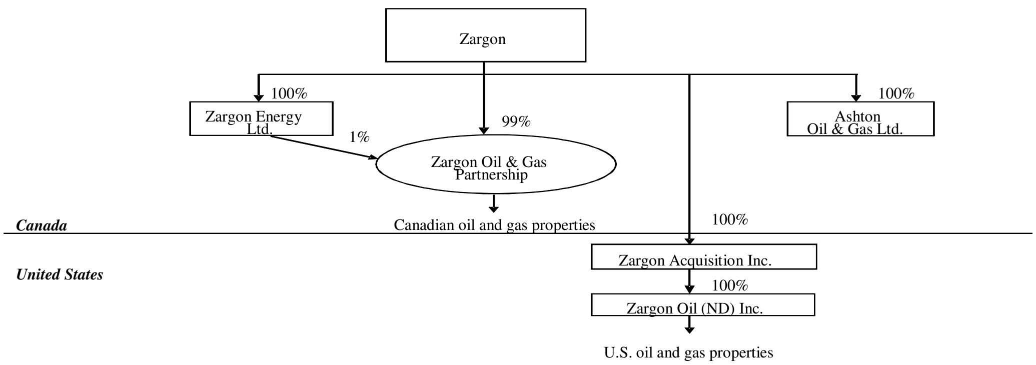
Inter-Corporate Relationships

The following are the names and percentages of voting securities that we own and the jurisdiction of incorporation, continuance or formation of our subsidiaries and partnership either, direct and indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation/ Formation
Zargon Energy Ltd.	100%	Corporation	Alberta
Zargon Oil & Gas Partnership	100%	General Partnership	Alberta
Ashton Oil & Gas Ltd.	100%	Corporation	Alberta
Zargon Acquisition Inc.	100%	Corporation	Wyoming
Zargon Oil (ND) Inc.	100%	Corporation	Delaware

Our Organization Structure

The following diagram describes the inter-corporate relationships between us and our material subsidiaries and partnership.



GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

On February 27, 2009, we entered into an arrangement agreement with Masters pursuant to which we agreed to acquire all of the issued and outstanding common shares of Masters pursuant to a plan of arrangement on the basis of, at the election of each Masters shareholder, cash or Trust Units or a combination thereof, subject to proration. The acquisition was completed on April 29, 2009, for total consideration of approximately 1.475 million Trust Units, $5.70 million in cash and the assumption of approximately $13.29 million of net debt (including adjustments and transactions costs) for a total transaction value of approximately $40.03 million. The acquisition provided us with approximately 1,230 boe/d of production, consisting of 630 bbl/d of oil and 3.60 MMcf/d of natural gas of which approximately 55 percent was from the operated Little Bow oil property in Southern Alberta. The acquisition also provided us with an Alkaline Surfactant Polymer tertiary oil recovery opportunity at the Little Bow property and more than 100 thousand net acres of undeveloped Alberta land.

On June 5, 2009, we completed a public offering of 2.365 million Trust Units on a bought deal basis (including 215,000 Trust Units issued pursuant to the exercise in full of the over-allotment option granted to the underwriters) at a price of $15.00 per Trust Unit for total gross proceeds of approximately $35.48 million.

On July 28, 2009, we entered into an arrangement agreement with Churchill pursuant to which we agreed to acquire all of the issued and outstanding common shares of Churchill pursuant to a plan of arrangement on the basis of, at the election of each Churchill shareholder, cash or Trust Units or a combination thereof, subject to a maximum of $4.60 million in cash. The plan of arrangement was completed on September 23, 2009 for a total consideration of approximately 0.555 million Trust Units, $0.11 million in cash and the assumption of approximately $6.85 million of net debt (including adjustments and transactions costs) for a total transaction value of approximately $16.31 million. The Churchill acquisition provided us with approximately 400 boe/d of production, consisting of 195 bbl/d of oil and 1.23 MMcf/d of natural gas in southern and west central Alberta and approximately 61 thousand net acres of undeveloped land.

On May 31, 2010, we completed an acquisition of working interests in various southern Alberta medium and heavy gravity oil pools with approximately 350 boe/d of existing production, along with approximately 6.9 thousand net acres of undeveloped land for a cash purchase price of approximately $25 million. The majority of the acquired assets were either situated adjacent to or in the vicinity of our Little Bow property. Following the acquisition, we held a 100 percent working interest in our proposed Little Bow Mannville I Pool Alkaline Surfactant Polymer tertiary recovery flood.

During the second and third quarters of 2010, we completed a series of dispositions of certain non-core assets for total proceeds of approximately $28.9 million. The asset sales related to a fully marketed property disposition package that included 17 non-core minor oil properties that were producing approximately 375 boe/d.

On September 9, 2010, we acquired all of the existing and outstanding common shares of Oakmont, a private oil and natural gas company, for total consideration of approximately 0.336 million Trust Units and the assumption of approximately $3.41 million of net debt, for a total transaction value of approximately $9.36 million. We acquired approximately 99.5 percent of the outstanding common shares of Oakmont pursuant to a share purchase agreement with Oakmont and the holders of the common shares of Oakmont and the balance of the outstanding common shares of Oakmont pursuant to the compulsory acquisition provisions of the *Business Corporations Act* (Alberta). At the time of the acquisition, Oakmont was producing approximately 280 boe/d consisting of 110 bbl/d of crude oil and 1.03 Mcf/d of natural gas. These assets are primarily located within our Alberta Plains South core area and are adjacent to our Little Bow and Grand Forks properties.

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 Exchangeable Shares were exchanged for common shares of Newco on the basis of 1.84716 common shares of Newco for each outstanding Exchangeable Share, and Newco acquired all of the assets and assumed all of the liabilities of the Trust; and (ii) on January 1, 2011, the Trust was dissolved and Old Zargon, Newco, ZAC, ZEI and Oakmont amalgamated. As a result of the Arrangement, we, together with our subsidiaries, own, directly or indirectly, the same assets that were owned by the Trust and its subsidiaries immediately prior to the Arrangement and we assumed all of the liabilities of the Trust and its subsidiaries immediately prior to the Arrangement.

On January 1, 2011 we amended and restated the Credit Agreement to incorporate the effects of the Arrangement.

During the first quarter of 2011, we completed property dispositions totalling $2.00 million. These disposition packages of minor non-core properties were part of our ongoing efforts to improve our operational footprint and focus.

On April 7, 2011 we completed a public offering of 1,725,000 Common Shares on a bought deal basis (including 225,000 Common Shares issued pursuant to the exercise in full of the over-allotment option granted to the underwriters) at $22.60 per Common Share for total gross proceeds of approximately $38.99 million.

On June 28, 2011, we amended the Credit Agreement to extend the term to June 27, 2012.

On July 7, 2011, we completed the disposition of our Antler and Manor, Williston Basin properties for a cash consideration, after adjustments, of approximately $23.87 million. In aggregate, these two southeast Saskatchewan properties were producing 260 bbl/d, and had included 7,800 net acres of undeveloped land.

On August 23, 2011, we completed the acquisition of a partner interest in the Alberta Plains North Jarrow property for a cash consideration, after adjustments, of $6.25 million. The acquisition brought approximately 1.30 mcf/d cubic feet per day of natural gas production. Most importantly, this transaction increased our interest to 100 percent in two Jarrow Units and the related compression and gathering facilities, which is consistent with our strategy to consolidate interests in our core properties.

On September 6, 2011, we completed the sale of 3,200 net acres of undeveloped land in the Whitecourt area of Alberta, for a cash consideration of $5.00 million. There was no production associated with the Whitecourt lands.

Significant Acquisitions

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

DESCRIPTION OF OUR BUSINESS

General

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

Our business plan is to deliver sustainable and profitable oil and natural gas property exploitation and production activities in the oil and natural gas industry. To accomplish this, we have adopted an integrated growth strategy with active exploitation and exploration drilling within our core areas, together with focused acquisitions, similar to the business strategy previously pursued by the Trust.

All of our activities are directed towards maximizing value for our 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 by paying monthly dividends to our Shareholders. We direct our efforts to increase the value of our assets through exploitation drilling and associated exploitation activities and enhanced oil recovery activities as well as by the periodic acquisition of undeveloped and producing oil and natural gas properties. We intend to acquire oil and natural gas producing properties and to participate in exploitation activities that are generally considered to be low risk in nature in the oil and natural gas industry. However, we intend to allocate a percentage of our annual capital budget to moderate risk exploitation and lower risk exploration opportunities on our properties.

In recent years our business has been challenged by rapidly increasing operating costs as we integrated properties from five corporate and one large property oil acquisition. With a refocused business plan, with eight clearly defined long-life oil exploitation initiatives, we will work to high-grade our property footprint and concentrate on cost containment initiatives. This may include the sale of non-strategic oil properties if attractive valuations can be realized. Also, during this period of low natural gas prices, we will complete a comprehensive review of our natural gas properties to identify well shut-in, facility consolidation and other fixed cost saving opportunities that will permit improved returns when natural gas prices improve.

Capital Expenditures

We may approve future capital expenditures or farmouts. Future capital expenditures on our properties will generally be of the type that are intended to maintain or improve production from our properties. We may finance capital expenditures from production revenues, the proceeds of the issue of additional Common Shares or other securities or from the proceeds of disposition of properties, borrowings, farmouts or with working capital.

We may acquire additional properties and related tangible equipment and fund such acquisitions from production revenues, the net proceeds of any issue of additional Common Shares or other securities or from the proceeds of disposition of properties, or from borrowings, farmouts 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.

Potential Acquisitions

We evaluate potential acquisitions of all types of oil and natural gas and other energy-related assets as part of our ongoing acquisition program. We are normally in the process of evaluating several potential acquisitions at any one time which individually or together could be material. We are not able to predict whether any opportunities will result in one or more acquisitions.

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 may 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.

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 condition*."

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 2012 by the renegotiation or termination of contracts or subcontracts other than with respect to our Credit Agreement which has a term date of June 27, 2012 and may be extended for a further 364-day period upon our request. If the credit facilities are not extended, they convert into a 365-day term loan and are repayable in full at the end of such term. See "*Risk Factors – Risks Relating to Our Business and Operations – Our Credit Agreement may be extended prior to June 27, 2012 and failure to extend may, and higher rates, will adversely affect our financial condition*".

Bankruptcy and Similar Procedures

There have been no bankruptcy, receivership or similar proceedings against us, or any voluntary receivership, bankruptcy or similar proceeding by the Trust within the three most recently completed financial years or proposed for us for our current financial year.

Material Restructuring Transactions

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

Human Resources

At December 31, 2011, we employed 69 full-time employees, including 62 office and 7 field employees.

Disclosure of Reserves Data and Other Oil and Natural Gas Information

This statement of reserves data and other oil and gas information set forth below is dated February 15, 2012. The effective date of the statement is December 31, 2011 and the preparation date of the statement is February 15, 2012. Readers should also refer to the Report of Management and Directors on Oil and Gas Disclosure attached hereto as Appendix A and the Report on Reserves Data by McDaniel attached hereto as Appendix B.

The reserves data set forth below is based upon an evaluation by McDaniel with an effective date of December 31, 2011 contained in the McDaniel Report. The reserves data summarizes our crude 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 McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. We engaged McDaniel to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

Our reserves are in Canada in the provinces of Alberta, British Columbia, Saskatchewan and Manitoba, and in the United States in North Dakota.

We determined the future net revenue and present value of future net revenue after income taxes by utilizing McDaniel's before income tax future net revenue and our estimate of income tax. Our estimate of cash income tax makes use of the following assumptions: corporate income tax at the current legislated rate; annual general and administrative expenses at the current rate; interest expense at the current rate; tax pool deductions utilizing our existing estimated $345.8 million of tax pools and forecasted additions to our tax pools from capital expenditures as forecast by McDaniel and any such other additional deductions and adjustments as is and would be consistent with the manner in which we file and would file future tax returns. The after-tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different.

Estimated values of future net revenues presented in the tables below do not represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of our 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 Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. For more information as to the risks involved, see "*Risk Factors – Risks Relating to Our Business and Operations*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2011
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
Proved								
Developed Producing	7,174	6,213	3,728	3,245	33,714	29,742	143	92
Developed Non-Producing	256	234	147	136	5,291	4,492	23	14
Undeveloped	233	216	205	183	365	336	3	3
Total Proved	**7,663**	**6,663**	**4,080**	**3,564**	**39,370**	**34,570**	**169**	**109**
Probable	**3,389**	**2,884**	**5,282**	**4,406**	**22,053**	**18,916**	**127**	**88**
Total Proved Plus Probable	**11,052**	**9,547**	**9,362**	**7,970**	**61,423**	**53,486**	**296**	**197**

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	513,006	404,879	337,669	292,115	259,090
Developed Non-Producing	23,091	17,926	14,326	11,754	9,859
Undeveloped	16,865	12,711	9,824	7,733	6,167
Total Proved	**552,962**	**435,516**	**361,819**	**311,602**	**275,116**
Probable	**388,138**	**221,159**	**139,136**	**92,492**	**63,361**
Total Proved Plus Probable	**941,100**	**656,675**	**500,955**	**404,094**	**338,477**

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) 0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	461,736	372,436	315,445	276,070	247,071
Developed Non-Producing	17,041	13,272	10,663	8,808	7,446
Undeveloped	12,510	9,328	7,127	5,538	4,351
Total Proved	**491,287**	**395,036**	**333,235**	**290,416**	**258,868**
Probable	**287,187**	**162,684**	**100,751**	**65,419**	**43,345**
Total Proved Plus Probable	**778,474**	**557,720**	**433,986**	**355,835**	**302,213**

BY PRODUCTION GROUP
as of December 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE (1) BEFORE INCOME TAXES (discounted at 10%/year) ($/bbl or $/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	224,977	33.85
	Heavy Oil (including solution gas and other by-products)	106,711	30.07
	Natural Gas (including by-products but excluding natural gas from oil wells)	30,131	1.00
	Total	**361,819**	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	291,030	30.56
	Heavy Oil (including solution gas and other by-products)	158,210	19.90
	Natural Gas (including by-products but excluding natural gas from oil wells)	51,715	1.15
	Total	**500,955**	

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

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2011
FORECAST PRICES AND COSTS

UNITED STATES

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
Proved								
Developed Producing	2,644	1,949	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	49	36	-	-	-	-	-	-
Total Proved	**2,693**	**1,985**	-	-	-	-	-	-
Probable	**652**	**480**	-	-	-	-	-	-
Total Proved Plus Probable	**3,345**	**2,465**	-	-	-	-	-	-

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

RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	90,042	64,291	49,038	39,901	33,903
Developed Non-Producing	-	-	-	-	-
Undeveloped	1,434	1,174	966	797	659
Total Proved	**91,476**	**65,465**	**50,004**	**40,698**	**34,562**
Probable	**33,334**	**14,256**	**8,038**	**5,380**	**3,975**
Total Proved Plus Probable	**124,810**	**79,721**	**58,042**	**46,078**	**38,537**

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	50,108	37,640	28,945	23,642	20,151
Developed Non-Producing	-	-	-	-	-
Undeveloped	834	689	573	479	404
Total Proved	**50,942**	**38,329**	**29,518**	**24,121**	**20,555**
Probable	**19,155**	**8,316**	**4,680**	**3,129**	**2,310**
Total Proved Plus Probable	**70,097**	**46,645**	**34,198**	**27,250**	**22,865**

BY PRODUCTION GROUP
as of December 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE [1] BEFORE INCOME TAXES (discounted at 10%/year) ($/bbl or $/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	50,004	25.19
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total	**50,004**	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	58,042	23.54
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total	**58,042**	

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

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2011
FORECAST PRICES AND COSTS

AGGREGATE

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
Proved								
Developed Producing	9,818	8,162	3,728	3,245	33,714	29,742	143	92
Developed Non-Producing	256	234	147	136	5,291	4,492	23	14
Undeveloped	282	252	205	183	365	336	3	3
Total Proved	**10,356**	**8,648**	**4,080**	**3,564**	**39,370**	**34,570**	**169**	**109**
Probable	**4,041**	**3,364**	**5,282**	**4,406**	**22,053**	**18,916**	**127**	**88**
Total Proved Plus Probable	**14,397**	**12,012**	**9,362**	**7,970**	**61,423**	**53,486**	**296**	**197**

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

RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	603,048	469,170	386,707	332,016	292,993
Developed Non-Producing	23,091	17,926	14,326	11,754	9,859
Undeveloped	18,299	13,885	10,790	8,530	6,826
Total Proved	**644,438**	**500,981**	**411,823**	**352,300**	**309,678**
Probable	**421,472**	**235,415**	**147,174**	**97,872**	**67,336**
Total Proved Plus Probable	**1,065,910**	**736,396**	**558,997**	**450,172**	**377,014**

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	511,844	410,076	344,390	299,712	267,222
Developed Non-Producing	17,041	13,272	10,663	8,808	7,446
Undeveloped	13,344	10,017	7,700	6,017	4,755
Total Proved	**542,229**	**433,365**	**362,753**	**314,537**	**279,423**
Probable	**306,342**	**171,000**	**105,431**	**68,548**	**45,655**
Total Proved Plus Probable	**848,571**	**604,365**	**468,184**	**383,085**	**325,078**

BY PRODUCTION GROUP
as of December 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE [1] BEFORE INCOME TAXES (discounted at 10%/year) ($/bbl or $/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	274,981	31.86
	Heavy Oil (including solution gas and other by-products)	106,711	30.07
	Natural Gas (including by-products but excluding natural gas from oil wells)	30,131	1.00
	Total	**411,823**	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	349,072	29.12
	Heavy Oil (including solution gas and other by-products)	158,210	19.90
	Natural Gas (including by-products but excluding natural gas from oil wells)	51,715	1.15
	Total	**558,997**	

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

TOTAL FUTURE NET REVENUE

(UNDISCOUNTED)
as of December 31, 2011
FORECAST PRICES AND COSTS

($000s) RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT AND RECLAMATION COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
Proved Reserves								
Canada	1,299,737	181,252	504,715	12,388	48,420	552,962	61,675	491,287
United States	274,679	72,224	101,957	1,196	7,826	91,476	40,534	50,942
Total	1,574,416	253,476	606,672	13,584	56,246	644,438	102,209	542,229
Proved Plus Probable Reserves								
Canada	2,296,780	338,203	836,485	127,606	53,386	941,100	162,626	778,474
United States	357,499	94,039	128,927	1,196	8,527	124,810	54,713	70,097
Total	2,654,279	432,242	965,412	128,802	61,913	1,065,910	217,339	848,571

Definitions and Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the McDaniel Report are based on the definitions and guidelines contained in the COGE Handbook, NI 51-101 and CSA 51-324. A summary of certain of those definitions is set forth below.

   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:

   - analysis of drilling, geological, geophysical and engineering data;
   - the use of established technology; and
   - specified economic conditions.

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

   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.

   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.

   Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

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

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.

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 certainly.

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.

Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) 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:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- 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.

Forecast Prices and Costs

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at December 31, 2011, inflation and exchange rates utilized in the McDaniel Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2011
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Bow River Hardisty API ($Cdn/bbl)	Alberta Heavy 12° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	Natural Gas AECO Price ($Cdn/ MMBTU)	Natural Gas Liquids FOB Field Gate ($Cdn/bbl)	Inflation Rate(1) %/year	Exchange Rate(2) ($US/ $Cdn)
Forecast									
2012	97.50	99.00	82.00	74.00	91.00	3.50	72.40	2.0	0.975
2013	97.50	99.00	82.00	74.00	91.00	4.20	74.10	2.0	0.975
2014	100.00	101.50	84.10	75.90	93.30	4.70	76.10	2.0	0.975
2015	100.80	102.30	84.70	76.50	94.10	5.10	77.10	2.0	0.975
2016	101.70	103.20	85.50	77.10	94.90	5.55	78.30	2.0	0.975
2017	102.70	104.20	86.30	77.90	95.80	5.90	79.40	2.0	0.975
2018	103.60	105.10	87.10	78.60	96.60	6.25	80.40	2.0	0.975
2019	104.50	106.00	87.80	79.20	97.50	6.45	81.30	2.0	0.975
2020	105.40	106.90	88.60	79.90	98.30	6.70	82.20	2.0	0.975
2021	107.60	109.20	90.40	81.60	100.30	6.85	84.00	2.0	0.975
2022	109.70	111.30	92.20	83.20	102.30	6.95	85.60	2.0	0.975
2023	111.90	113.60	94.00	84.80	104.30	7.05	87.20	2.0	0.975
2024	114.10	115.80	95.90	86.50	106.40	7.20	89.00	2.0	0.975
2025	116.40	118.10	97.80	88.20	108.50	7.40	90.90	2.0	0.975
2026	118.80	120.50	99.80	90.10	110.80	7.55	92.70	2.0	0.975
Thereafter:	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	2.0	0.975

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by us (before the impact of financial risk management contracts) for the year ended December 31, 2011, were $3.45/Mcf for natural gas, $84.96/bbl for crude oil, $79.04/bbl for natural gas liquids and $74.03/bbl for heavy oil.

Future Development Costs

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

CANADA

	Forecast Prices and Costs	
Year ($000s)	Proved Reserves	Proved Plus Probable Reserves
2012	5,085	31,625
2013	5,753	22,887
2014	1,092	17,196
2015	-	24,301
2016	-	13,680
Thereafter	458	17,917
Total Undiscounted	12,388	127,606
Total Discounted at 10%	10,900	99,815

UNITED STATES

	Forecast Prices and Costs	
Year ($000s)	Proved Reserves	Proved Plus Probable Reserves
2012	1,196	1,196
2013	-	-
2014	-	-
2015	-	-
2016	-	-
Thereafter	-	-
Total Undiscounted	1,196	1,196
Total Discounted at 10%	1,141	1,141

AGGREGATE

	Forecast Prices and Costs	
Year ($000s)	Proved Reserves	Proved Plus Probable Reserves
2012	6,281	32,821
2013	5,753	22,887
2014	1,092	17,196
2015	-	24,301
2016	-	13,680
Thereafter	458	17,917
Total Undiscounted	13,584	128,802
Total Discounted at 10%	12,041	100,956

Notes:

(1) We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and the issuance of Common Shares or other securities.

(2) 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 McDaniel Report. Failure to develop those reserves would have a negative impact on our future cash flow.

(3) At this time, there are no expectations that the costs of funding would make development of a property uneconomic.

(4) The interest or other costs of external funding are not included in the reserves and future net revenue estimates. This 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.

(5) Estimated future abandonment and reclamation costs related to a property have been taken into account by McDaniel in determining reserves that should be attributed to a property. Reasonable estimated future well abandonment costs were

deducted in determining the aggregate future net revenue. No allowance was made, however, for reclamation of well sites or the abandonment and reclamation of any facilities.

(6) The forecast price and cost assumptions assume the continuance of current laws and regulations.

(7) The extent and character of all factual data supplied to McDaniel were accepted by McDaniel as represented. No field inspection was conducted.

Reconciliations of Changes in Reserves

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

CANADA

	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2010	8,078	3,196	11,274	4,101	1,991	6,092	44,262	22,268	66,530
Extensions & Improved Recovery	668	678	1,346	311	3,564	3,875	662	2,742	3,404
Technical Revisions	540	(322)	218	146	(282)	(136)	1,904	(3,421)	(1,517)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	48	16	64	34	15	49	2,532	1,235	3,767
Dispositions	(413)	(179)	(592)	(4)	(6)	(10)	(344)	(142)	(486)
Economic Factors	-	-	-	-	-	-	(1,626)	(629)	(2,255)
Production	(1,258)	-	(1,258)	(508)	-	(508)	(8,020)	-	(8,020)
December 31, 2011	7,663	3,389	11,052	4,080	5,282	9,362	39,370	22,053	61,423

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

UNITED STATES

	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2010	2,838	874	3,712	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	54	(222)	(168)	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(199)	-	(199)	-	-	-	-	-	-
December 31, 2011	2,693	652	3,345	-	-	-	-	-	-

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

AGGREGATE

	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIATED AND NON-ASSOCIATED GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2010	10,916	4,070	14,986	4,101	1,991	6,092	44,262	22,268	66,530
Extensions & Improved Recovery	668	678	1,346	311	3,564	3,875	662	2,742	3,404
Technical Revisions	594	(544)	50	146	(282)	(136)	1,904	(3,421)	(1,517)
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	48	16	64	34	15	49	2,532	1,235	3,767
Dispositions	(413)	(179)	(592)	(4)	(6)	(10)	(344)	(142)	(486)
Economic Factors	-	-	-	-	-	-	(1,626)	(629)	(2,255)
Production	(1,457)	-	(1,457)	(508)	-	(508)	(8,020)	-	(8,020)
December 31, 2011	10,356	4,041	14,397	4,080	5,282	9,362	39,370	22,053	61,423

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel 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. In our practice, proved undeveloped reserves tend to be those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from our gathering systems. In addition, such reserves may relate to planned infill drilling locations. Probable undeveloped reserves may be reserves tested or indicated by analogy to be productive, infill drilling location and lands contiguous to production. In either case, the majority of undeveloped reserves are planned to be on stream within a two-year time frame. Undeveloped proved and probable reserves represent only about four percent of our proved and probable reserves.

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 – Risks Relating to Our Business and Operations*".

Proved Undeveloped Reserves

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

Year	**Light and Medium Oil (Mbbl)**		**Heavy Oil (Mbbl)**		**Natural Gas (MMcf)**		**NGLs (Mbbl)**	
	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	326	551	45	45	438	635	-	-
2009	-	181	-	45	-	317	-	-
2010	349	446	206	251	79	187	4	4
2011	77	282	55	205	186	365	-	3

A total of 487 Mbbl of oil, 365 MMcf of gas and 3 Mbbl of NGLs were assigned as proved undeveloped reserves at December 31, 2011, representing 2.6% of our total proved reserves. In estimating future net revenue McDaniel reviewed our future development plans in order to estimate and deduct future development costs. Therefore the future development costs as set out under "*Future Development Costs*" are consistent with our future development plans. The proved undeveloped reserves are generally associated with infill/development drilling locations supported by recent drilling results and offset well data. The largest portion of the capital associated with developing proved undeveloped reserves is expected to be spent in 2012, with carryover into 2013. Within the McDaniel Report, 100% of the capital is scheduled to be spent over the next two years.

Probable Undeveloped Reserves

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

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	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	396	682	376	376	3,605	6,574	4	7
2009	144	407	-	114	25	3,041	-	4
2010	286	385	462	481	99	698	1	1
2011	423	731	3,465	3,667	2,572	2,878	31	43

A total of 4,398 Mbbl of oil, 2,878 MMcf of gas and 43 Mbbl of NGLs were assigned as gross probable undeveloped reserves in 2011, representing approximately 37.5% of our total probable reserves or 14.4% of total proved plus probable reserves. The majority of the probable reserves assignment for the company relates to properties which have proved producing reserves assigned. The bulk of the probable undeveloped reserves are assigned to projects which are actively underway and are contemplated in our upcoming capital programs. Of the total future development costs assigned in the McDaniel Report for probable undeveloped reserves 37% are forecast to be spent in 2012 and 2013.

Significant Factors or Uncertainties Affecting Reserves Data

Our reserves have been evaluated in accordance with NI 51-101 by McDaniel, an independent engineering firm, effective December 31, 2011. Our reserves committee has reviewed the scope and methodology of McDaniel's evaluation; any significant new discoveries, additions, revisions and acquisitions, and reviewed the assumptions and consistency with prior years.

Our reserves are characterized by a high developed producing component. This reflects our core competencies of oil exploitation, increasing oil production and reserves from existing reservoirs. It is a technically complex business and each oil reservoir is treated differently depending on the interrelationships of the reservoir rock, fluids, pressures, wells and surface facilities. As circumstances change and additional data becomes available, our reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information.

Our evaluated oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent in an oil and gas producing company as described in our management's discussion and analysis relating to our 2011 annual audited consolidated financial statements under the heading "*Business Risks And Outlooks*", which is incorporated herein by reference. See also "*Risk Factors – Risks Relating to Our Business and Operations*" below.

Other Oil and Gas Information

Oil and Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2011. 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. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2011. **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 within the Western Provinces in Canada and in North Dakota in the United States. Each region offers a large undeveloped land base, a vast seismic database, and significant ownership and operatorship in production facilities.

Williston Basin

We have a long and profitable history in the Williston Basin core area, which encompasses a portion of southeast Saskatchewan, southwest Manitoba and three counties of North Dakota. The area holds 29 percent of our proved and probable oil and liquids reserves and accounted for 27 percent of our oil and liquids production in 2011.

In the Williston Basin, we are working three types of oil exploitation projects. In 2011, the majority of our Williston Basin drilling were Midale drainage locations, which are characterized by low permeability reservoirs that are generally partially pressure supported by either weak aquifers or, in some cases, by non-operated offsetting mature waterfloods. Production from Midale type wells are characterized by relatively low rates, moderately high water cuts, but shallow production declines. Ultimately, as many as 30 of these drainage locations are expected to be drilled over the next three years at the Weyburn, Elswick, Midale, Ralph and Steelman properties. The McDaniel Report has booked only two of these undeveloped Williston Basin Midale horizontal drainage locations.

Exploiting un-drained Frobisher seismically defined targets is the second type of Williston Basin oil exploitation project that is being pursued. These Frobisher targets are characterized by higher permeability rock with full aquifer pressure support. Successful wells have high initial oil production rates, but high initial declines as the flank water encroaches on the wells. The economics of these Frobisher programs can be very robust, as demonstrated by our 17 well 2009-2010 Steelman Frobisher program where McDaniel assigned average proved and probable reserves in excess of 75 thousand barrels of oil per well. Over the next three years, we expect to drill a minimum of 15 Frobisher locations on already identified structures at the Weyburn, Steelman and Mackobee Coulee properties. The McDaniel Report does not include any of these undeveloped Williston Basin Frobisher horizontal locations.

Our final Williston Basin exploitation project entails the unlocking of thick Mississippian low permeability carbonate targets through horizontal multi-frac wells in conjunction with the implementation of full-field waterfloods. In particular, we have significant "tight oil waterflood potential" with considerable oil-in-place resources in the low permeability Daly, Virden, Workman and Truro properties. In 2012, we will advance the de-risking program for these long term opportunities with a second Truro multi-frac location and a two well multi-frac horizontal injector producer pilot waterflood at Daly, Manitoba. The McDaniel Report includes only one of these undeveloped Williston Basin "tight oil" multi-frac horizontal locations.

Alberta Plains South

Our Alberta Plains South core area holds 31 percent of our proved and probable oil and liquids reserves and contributed 25 percent of our 2011 oil and liquids production. During 2011, we made significant progress with the horizontal development of the Taber South Sunburst pool and implemented a waterflood secondary recovery project. Exploitation activities this year will include further horizontal development drilling, expansion of the waterflood secondary recovery project and step-out drilling to expand pool boundaries and exploit newly acquired assets. At Grand Forks, oil exploitation will include facility optimization, and modifications to enhance oil recoveries.

The largest and most important property in this core area is Little Bow with its tertiary oil recovery opportunities plus a number of waterflood and production optimization projects. Over the last three years, we assembled assets at Little Bow through a number of property and corporate acquisitions, which also consolidated a position in the ASP project.

Earlier this year, we announced that we would proceed with detailed engineering, regulatory applications and the procurement of long-lead time equipment for the Little Bow Upper Mannville I pool ASP project. This tertiary oil recovery project entails the injection of chemicals in a water solution into a partially depleted reservoir to recover incremental oil reserves. The project schedule anticipates first chemical injections in July 2013, with a significant oil production response forecast to occur by January 2014. The McDaniel Report has assigned 4.15 Mmboe of probable undeveloped reserves to our working interest in Phases 1 and 2 of the project. Future costs to develop the first two phases of the project are estimated at $103.5 million and are comprised of $47.8 million for the field and related capital (2012-2015) and $55.7 million for the cost of the chemical injections (2013-2019). Incorporating all future capital (including chemical costs), the Little Bow ASP Phase 1 and 2 finding and development costs are estimated to be $24.98 per barrel of oil equivalent. Targeted field netbacks for the Little Bow ASP Phase 1 and 2 projects are in the $50 to $60 per barrel of oil range.

In 2012, Zargon is projecting to spend $21 million of Phase 1 Little Bow ASP capital with 75 percent of the expenditures occurring in the second half of the year. An additional $11 million of capital expenditures is forecast to be spent in 2013, with the remainder of the capital costs relating to the project's Phase 2 implementation scheduled for 2014 and 2015.

Alberta Plains North

Our Alberta Plains North core area holds 40 percent of our proved and probable oil and liquids reserves. During 2011, the most significant oil exploitation projects included a three well multi-frac horizontal drilling test program at Hamilton Lake targeting large Viking reservoirs, along with the three well step-out development and eventual waterflood implementation of a new Glauconite oil pool at Killam/Jarrow. Facility and pumping optimizations at Bellshill Lake, Killam South and Provost also provided additional oil volumes.

Alberta Plains North provided 48 percent of our total natural gas production in 2011, primarily from the Jarrow, Hamilton Lake, Highvale and Progress areas. In 2012, selective investments in facility optimization projects will maximize returns from these natural gas properties in a weak natural gas price environment. We will also pursue sale, farmout and swap transactions on our large undeveloped land base to maximize returns and create a more concentrated property footprint.

In 2011, three multi-frac horizontal locations were drilled at the 47 section wholly-owned Hamilton Lake property. After an average of five months of production, January 2012 production for the three wells averaged 48 bbl/d of oil per well with a 73 percent water cut. Unlocking the potential of Hamilton Lake's large oil-in-place resource with stimulated horizontal wells and a reactivated waterflood will be a high priority in 2012. In the first quarter of 2012, two wells have been drilled and completed and will be production tested shortly. Two additional wells are scheduled for this summer and additional locations are expected to be drilled this fall and winter. Success at Hamilton Lake could lead to more than 30 additional horizontal oil locations. The McDaniel Report has not booked any of these undeveloped Hamilton Lake Viking multi-frac horizontal locations.

In addition to Hamilton Lake, 2012 capital will be directed to the Killam property, where a three well horizontal development drilling program will be completed in the first quarter. This program will be followed by the implementation of a pilot waterflood and further delineation drilling. With further derisking, the Killam property is expected to be a significant oil exploitation project that could require as many as 20 horizontal drainage wells to optimally exploit under a waterflood scheme. The McDaniel Report has booked only three of these undeveloped Killam Glauconite horizontal locations.

Additional 2012 Alberta expenditures will be directed to oil exploitation projects at Bellshill Lake, where further infill drilling plus oil treating and water disposal upgrades are expected to deliver increased oil production and reserves.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2011.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada								
British Columbia	-	-	-	-	-	-	3.0	1.4
Alberta	402.0	214.6	509.0	264.2	516.0	310.3	641.0	374.6
Saskatchewan	205.0	158.4	126.0	100.8	-	-	-	-
Manitoba	65.0	65.0	8.0	7.5	-	-	-	-
United States								
North Dakota	61.0	59.7	42.0	41.5	-	-	-	-
Total	733.0	497.7	685.0	414.0	516.0	310.3	644.0	376.0

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2011.

	Undeveloped Acres	
(thousand acres)	Gross	Net
Alberta	514	366
British Columbia	6	4
Saskatchewan	53	41
Manitoba	3	3
United States	8	8
Total	584	422

With respect to our undeveloped land inventory and farm-in agreements, we have commitments from industry participants as follows**:**

- one well to be drilled prior to April 1, 2012, in the Peace River Arch area of Alberta;
- one well has been drilled prior to February 29, 2012, but the Farmee has not yet made the election on option to drill 2 additional wells, in the Peace River Arch area of Alberta; and
- one well to be drilled prior to May 30, 2012, in the Edson area of Alberta.

Rights to explore, develop and exploit 113,483 net acres of our undeveloped land holdings in Canada and 500 net acres of our undeveloped land holdings in the United States are scheduled to expire by December 31, 2011.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates, electricity rates and interest rates in the normal course of our operations. A variety of derivative instruments are used to reduce 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 amongst a number of financially strong counterparties. For information in relation to our marketing arrangements, see "*Marketing Arrangements*".

For details of our material commitments to sell natural gas and crude oil that were outstanding at December 31, 2011 see note 16 to our 2011 annual audited consolidated financial statements, which is incorporated herein by reference.

Additional Information Concerning Abandonment and Reclamation Costs

As at December 31, 2011, we had 1,598 net wells capable of production for which we expect to incur abandonment and reclamation costs.

The total amount of abandonment and reclamation costs, net of estimated salvage values that we expect to incur are summarized in the following table.

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, 2011	$61,914	$15,336
Anticipated to be paid in 2012	441	420
Anticipated to be paid in 2013	1,397	1,221
Anticipated to be paid in 2014	1,071	844

We have estimated the net present value of our total asset retirement obligations to be $96.6 million as at December 31, 2011 based on a total future liability of $130.73 million. The future net revenues disclosed in this Annual Information Form based on the McDaniel Report do not contain an allowance for abandonment and reclamation costs for batteries and salvage values are deducted. The McDaniel Report deducted $61.91 million (undiscounted) and $15.34 million (10 percent discount using forecast prices and costs for proved and probable reserves) for abandonment and reclamation costs in estimating the future net revenue disclosed in this Annual Information Form.

We do not expect to pay any material amounts with respect to abandonment and reclamation costs in the next two financial years.

Tax Horizon

We did not pay Canadian income taxes in 2011. During 2011, we incurred current income taxes in the United States of $1.53 million, compared to $1.93 million in 2010.

We are a taxable entity under the *Income Tax Act* (Canada); however, based on the current forward commodity strip, our tax pools are expected to shelter us from paying cash taxes in Canada until 2016. Our tax pools shelter will last an expected additional two years due removal of the tax partnership deferral. Under our prior trust structure, distributions were deductible; but as a corporation dividends are not deductible by us.

Costs Incurred

The following table summarizes capital expenditures related to our activities for the year ended December 31, 2011.

($ million)	Canada	United States	Total
Property Acquisition Costs:			
Proved Properties [(1)]	5.98	0.26	6.24
Unproved Properties	(23.37)	-	(23.37)
Corporate Acquisitions	-	-	-
Development Costs [(2)]	57.85	1.39	59.24
Exploration Costs [(3)]	6.18	-	6.18
Total	46.64	1.65	48.29

Notes:

(1) Acquisitions are net of disposition of properties.

(2) Development and facilities expenditures.

(3) Cost of land acquired, geological and geophysical capital expenditures and drilling costs for 2011 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, 2011.

CANADA	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Oil	1.0	1.0	37.0	31.8
Natural Gas	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	4.0	2.5	-	-
Total	5.0	3.5	37.0	31.8

UNITED STATES	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Oil	-	-	-	-
Natural Gas	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	-	-	-	-

In 2012, we are budgeted to invest approximately $66 million in our core areas, which is comprised of a net $45 million of field capital and $21 million of ASP related expenditures. The entire amount is dedicated to exploration, exploitation, development and optimization of our existing assets. This amount does not include any capital for acquisitions, which will be pursued on an opportunistic basis.

For most details regarding our most important current exploration and development activities for 2012 see, "*– Other Oil and Gas Information – Oil and Gas Properties*" above.

Production Estimates

The following table sets out the volumes of gross production estimated in the McDaniel Report for the year ended December 31, 2012, which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data and Other Oil and Natural Gas Information*".

CANADA	Light and Medium Oil	Natural Gas	Natural Gas Liquids	Heavy Oil	BOE
	(bbl/d)	(Mcf/d)	(bbl/d)	(bbl/d)	(boe/d)
Total Proved	3,038	19,940	79	1,592	8,033
Total Probable	244	908	3	71	469
Total Proved Plus Probable	3,282	20,848	82	1,663	8,502

UNITED STATES	Light and Medium Oil	Natural Gas	Natural Gas Liquids	Heavy Oil	BOE
	(bbl/d)	(Mcf/d)	(bbl/d)	(bbl/d)	(boe/d)
Total Proved	548	-	-	-	548
Total Probable	14	-	-	-	14
Total Proved Plus Probable	562	-	-	-	562

Production History and Prices Received

The following tables summarize certain information in respect of our production, product prices received, royalties paid, production expenses and resulting netbacks for the periods indicated.

CANADA

	Quarter Ended			
	2011			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production:				
Gas (Mcf/d)	21,956	22,103	21,909	21,918
Light and Medium Crude Oil (bbl/d)	3,487	3,320	3,042	3,943
Heavy Oil (bbl/d)	1,528	1,338	1,386	1,311
Natural Gas Liquids (bbl/d)	82	90	88	84
Combined (boe/d)	8,755	8,432	8,168	8,991
Average Price Received: (1)				
Gas ($/Mcf)	3.02	3.51	3.74	3.55
Light and Medium Crude Oil ($/bbl)	91.53	79.78	94.51	78.33
Heavy Oil ($/bbl)	78.65	70.55	79.01	66.83
Natural Gas Liquids ($/bbl)	88.04	75.25	87.31	65.47
Combined ($/boe)	58.57	52.62	59.57	53.37
Royalties Paid:				
Gas ($/Mcf)	0.17	0.29	0.60	0.40
Light and Medium Crude Oil ($/bbl)	15.95	16.83	18.78	12.88
Heavy Oil ($/bbl)	12.19	14.15	14.36	10.27
Natural Gas Liquids ($/bbl)	8.32	12.09	34.58	4.31
Combined ($/boe)	8.97	9.75	11.41	8.17
Production Costs:				
Gas ($/Mcf)	2.36	2.40	3.03	2.80
Light and Medium Crude Oil ($/bbl)	23.31	20.18	19.27	16.33
Heavy Oil ($/bbl)	18.99	16.97	15.52	13.45
Natural Gas Liquids ($/bbl)	21.25	18.10	17.15	13.18
Combined ($/boe)	18.71	17.13	18.11	16.07
Netback Received: (2)				
Gas ($/Mcf)	0.49	0.82	0.11	0.35
Light and Medium Crude Oil ($/bbl)	52.27	42.77	56.46	49.12
Heavy Oil ($/bbl)	47.47	39.43	49.13	43.11
Natural Gas Liquids ($/bbl)	58.47	45.06	35.58	47.98
Combined ($/boe)	30.89	25.74	30.05	29.13

Notes:
(1) Average price received is calculated before the impact of realized risk management gains or losses.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues before realized risk management gains or losses.

UNITED STATES

	Quarter Ended			
	2011			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production:				
Gas (Mcf/d)	-	-	-	-
Light and Medium Crude Oil (bbl/d)	523	582	518	555
Heavy Oil (bbl/d)	-	-	-	-
Natural Gas Liquids (bbl/d)	-	-	-	-
Combined (boe/d)	523	582	518	555
Average Price Received: (1)				
Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	82.21	77.84	89.02	75.10
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	82.21	77.84	89.02	75.10
Royalties Paid:				
Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	21.05	19.74	22.25	19.21
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	21.05	19.74	22.25	19.21
Production Costs:				
Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	11.74	13.12	13.38	11.16
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	11.74	13.12	13.38	11.16
Netback Received: (2)				
Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	49.42	44.99	53.39	44.73
Heavy Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	49.42	44.99	53.39	44.73

Notes:

(1) Average price received is calculated before the impact of realized risk management gains or losses.

(2) Netbacks are calculated by subtracting royalties and operating costs from revenues before realized risk management gains or losses.

AGGREGATE

	Quarter Ended 2011			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production:				
Gas (Mcf/d)	21,956	22,103	21,909	21,918
Light and Medium Crude Oil (bbl/d)	4,009	3,902	3,560	4,498
Heavy Oil (bbl/d)	1,528	1,338	1,386	1,311
Natural Gas Liquids (bbl/d)	82	90	88	84
Combined (boe/d)	9,278	9,014	8,686	9,546
Average Price Received: (1)				
Gas ($/Mcf)	3.02	3.51	3.74	3.55
Light and Medium Crude Oil ($/bbl)	90.32	79.49	93.71	77.93
Heavy Oil ($/bbl)	78.65	70.55	79.01	66.83
Natural Gas Liquids ($/bbl)	88.04	75.25	87.31	65.47
Combined ($/boe)	59.91	54.25	61.32	54.64
Royalties Paid:				
Gas ($/Mcf)	0.17	0.29	0.60	0.40
Light and Medium Crude Oil ($/bbl)	16.62	17.26	19.28	13.66
Heavy Oil ($/bbl)	12.19	14.15	14.36	10.27
Natural Gas Liquids ($/bbl)	8.32	12.09	34.58	4.31
Combined ($/boe)	9.65	10.40	12.05	8.81
Production Costs:				
Gas ($/Mcf)	2.36	2.40	3.03	2.80
Light and Medium Crude Oil ($/bbl)	21.80	19.12	18.41	15.69
Heavy Oil ($/bbl)	18.99	16.97	15.52	13.45
Natural Gas Liquids ($/bbl)	21.25	18.10	17.15	13.18
Combined ($/boe)	18.32	16.87	17.83	15.79
Netback Received: (2)				
Gas ($/Mcf)	0.49	0.82	0.11	0.35
Light and Medium Crude Oil ($/bbl)	51.90	43.11	56.02	48.58
Heavy Oil ($/bbl)	47.47	39.43	49.13	43.11
Natural Gas Liquids ($/bbl)	58.47	45.06	35.58	47.98
Combined ($/boe)	31.94	26.98	31.44	30.04

Notes:
(1) Average price received is calculated before the impact of realized risk management gains or losses.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues before realized risk management gains or losses.

The following table indicates our average daily production from our core areas for the year ended December 31, 2011.

	Natural Gas (Mcf/d)	**Light and Medium Crude Oil** (bbl/d)	**Heavy Oil** (bbl/d)	**NGLs** (bbl/d)	**BOE** (boe/d)
Williston Basin	504	2,449	-	1	2,534
Alberta Plains South	3,345	422	1,274	25	2,278
Alberta Plains North	18,123	1,120	117	60	4,318
Total	21,972	3,991	1,391	86	9,130

Marketing Arrangements

Natural Gas

Most of our natural gas production was sold by spot sale contracts and Alberta index prices were received. In order to control and manage credit risk and ensure competitive bids, we engage with a number of reputable counterparties for our natural gas transactions. The integration and application of these strategies resulted in an average realized price (after realized risk management gains/losses) of $3.45 per Mcf in 2011 compared to $3.87 per Mcf in 2010.

Oil and Natural Gas 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 general, we market our oil production with various purchasers under one month renewable contracts and receive posted reference prices with adjustments for quality and transportation. In 2011, our average realized oil and liquids price (after realized risk management gains/losses) was $76.19 per bbl compared to $69.95 per bbl in 2010.

Risk Management Activities

Zargon's commodity price risk management policy, which is approved by the Board of Directors, allows the sale of up to a 50 percent maximum of its estimated oil production for up to a 24 month period in order to meet capital program and dividend obligations in the event of significant commodity price declines. Because our risk management strategy is protective in nature and is designed to guard us against extreme effects on funds flow from sudden falls in prices and revenue, upward price spikes tend to produce overall losses. For details of our risk management activities in 2011 see our management's discussion and analysis relating to our 2011 annual audited consolidated financial statements under the heading "*Risk Management Activities*", which is incorporated herein by reference.

Acquisitions and Dispositions

During 2011, we completed several property transactions including the acquisition and disposition of oil and natural gas properties. In aggregate, we recorded $23.37 million on net property dispositions in the year.

Environmental Policies

We have an environmental policy in place as part of our commitment to protecting the environment while conducting our operations. Our environmental policy states that:

- Operating in an environmentally responsible manner is key to insuring our continued growth and the industry.
- Sound environmental management is an integral component of a good business plan. Environmental stewardship reduces costs and corporate liability. It enhances shareholder value, boosts employee morale and enhances our image in the eyes of regulators and the public.
- Managing our environmental responsibilities is a team effort requiring the commitment of management, employees and contractors.
- Preventing environmental damage is cheaper than repairing damage.
- An effective environmental program helps operations staff to understand and comply with environmental laws and regulations and to minimize the costs and liabilities associated with environmental damage. It helps meet the concerns of investors, analysts, bankers, partners and the public that environmental issues are being managed properly and will provide a due-diligence defence in the event of an environmental incident.

Our management also monitors developments related to the climate change and other environmental laws and regulations.

We are not currently impacted by proposed environmental laws and regulations relating to the control of greenhouse gases (see "*Industry Conditions – Climate Change Regulation*") as none of our facilities qualify and currently, no facility production qualifies under the criteria described in the Updated Action Plan (as defined therein). We will continue to monitor the regulatory developments and any impact that they may have on our future compliance costs.

Finding, Development and Acquisition Costs (1)

The following table sets forth our finding and development costs ("**F&D**") and our finding, development and acquisition costs ("**FD&A**") for the periods indicated. We have presented finding and development costs below both including and excluding acquisitions and dispositions. While NI 51-101 requires that the effects of acquisitions and dispositions be excluded, we have included these items because we believe that acquisitions and dispositions can have a significant impact on our ongoing reserve replacement costs and that excluding these amounts could result in an inaccurate portrayal of our cost structure.

	2011	**2010**	**2009**
Total net capital expenditures ($ millions) (2) - unaudited	48.29	71.38	103.83
Total net capital expenditures plus change in forecast proved plus probable future development costs ($ millions) (2)	144.52	79.62	100.65
Proved plus probable reserves (Mmboe)			
Open	32.39	32.24	29.72
Discoveries and extensions	5.77	3.07	1.78
Acquisitions and dispositions	0.06	1.53	4.22
Revisions	(0.59)	(0.84)	0.12
Production	(3.34)	(3.61)	(3.60)
Close	34.29	32.39	32.24
Proved FD&A costs ($/boe) (3)	21.11	24.60	19.24
Proved three-year average FD&A costs ($/boe) (3)	21.30	21.13	20.47
Proved plus probable FD&A costs ($/boe) (4)	27.58	21.18	16.45
Proved plus probable three-year average FD&A costs ($/boe) (4)	21.48	18.83	19.57
Proved F&D costs ($/boe) (3)	33.48	32.84	17.98
Proved three-year average F&D costs ($/boe) (3)	28.50	22.18	19.06
Proved plus probable F&D costs ($/boe) (4)	32.41	30.79	22.77
Proved plus probable three-year average F&D costs ($/boe) (4)	30.06	24.80	23.29

Notes:

(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

(2) Amounts exclude additions for administrative assets.

(3) Amounts are calculated including the change in proved future development costs (2011 - $(6.71) million; 2010 - $12.49 million; 2009 - $(2.23) million).

(4) Amounts are calculated including the change in proved plus probable future development costs.

OUR CAPITAL STRUCTURE

Share Capital

Our authorized share capital consists of an unlimited number of Common Shares without nominal or par value and 10,000,000 preferred shares without nominal or par value issuable in series (the "**Preferred Shares**"). The following is a summary of the rights, privileges, restrictions and conditions which attach to our securities. The inclusion of Preferred Shares in our authorized share capital is intended to provide us with the flexibility to raise a limited amount of future capital in the form of preferred shares. At the present time, our management is not aware of any financing structures for oil and gas companies that involve the issuance of preferred shares. The Preferred Shares will not be utilized as a defence to any take-over bid.

Common Shares

Holders of our 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).

Holders of our Common Shares will be entitled to receive dividends as and when declared by our Board of Directors on the Common Shares as a class, subject to 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.

Holders of our Common Shares will be entitled 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, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes ranking in priority to the Common Shares in respect of a return of capital on dissolution, 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 a return of capital on dissolution, in such of our assets as are available for distribution.

Preferred Shares

The Preferred Shares may be issued in one or more series, at any time or from time to time. Before any shares of a particular series are issued, our Board of Directors will fix the number of shares that will form such series and will, subject to the limitations set out in the preferred share terms described below, fix the designation, rights, privileges, restrictions and conditions to be attached to the Preferred Shares of such series, including, but without in any way limiting or restricting the generality of the foregoing, the rate, amount or method of calculation of dividends thereon, the time and place of payment of dividends, the consideration for and the terms and conditions of any purchase for cancellation, retraction or redemption thereof, conversion or exchange rights (if any), and whether into or for our securities or otherwise, voting rights attached thereto (if any), the terms and conditions of any share purchase or retirement plan or sinking fund, and restrictions on the payment of dividends on any shares other than Preferred Shares or payment in respect of capital on any shares in our capital or creation or issue of debt or equity securities; the whole subject to filing of Articles of Amendment setting forth a description of such series including the designation, rights, privileges, restrictions and conditions attached to the shares of such series. Notwithstanding the foregoing: (a) 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; and (b) other than in the case of a failure to declare or pay dividends specified in any series of the Preferred Share, the voting rights attached to the Preferred Shares will be limited to one vote per Preferred Share at any meeting where the Preferred Shares and Common Shares vote together.

Credit Facility

We have a syndicated credit facility with a $180 million borrowing base. A $300 million demand debenture on our assets has been provided as security for these facilities. The facilities are fully revolving for a 365 day period with the provision for an annual extension at the option of the lenders and upon notice from us. The next renewal date is June 27, 2012. Should the facilities not be renewed, they convert to one year non-revolving term facilities at the end of the revolving 365 day period. Repayment would not be required until the end of the non-revolving term.

Interest rates fluctuate under the syndicated facilities with Canadian prime, US prime and US base rates plus an applicable margin between 50 basis points and 200 basis points as well as with Canadian banker's acceptance and LIBOR rates plus an applicable margin between 200 basis points and 350 basis points. Unused amounts under the facility are subject to standby fees. In the normal course of operations we enter into various letters of credit. The letters of credit reduce the amount of our available credit facilities.

DIRECTORS AND OFFICERS

Directors

The name, municipality of residence, principal occupation for the prior five years and position (including with a predecessor of us), of each of our directors is as follows:

Name and Municipality of Residence	Director Since	Principal Occupation
Craig H. Hansen Calgary, Alberta	1992	Our President & Chief Executive Officer since 1993.
K. James Harrison (2) (3) Oakville, Ontario	1995	Mr. Harrison is our Chairman. He is the founder of K.J. Harrison & Partners Inc., a private client investment management firm in Toronto, Ontario. Prior to 2000, he was the Vice-Chairman and Chief Executive Officer of Connor Clark Ltd.
Kyle D. Kitagawa (1) (4) Calgary, Alberta	2001	Mr. Kitagawa has been an independent businessman since 2003. In addition, Mr. Kitagawa serves as Chairman of Canadian Energy Services & Technology Corp. and Coral Hill Energy Ltd. and is also a director of ProspEx Resources Ltd. Prior directorships include Advanced Mobile Power Systems, LLC, Esprit Exploration Ltd., Ferus Trust, Independent Energy Ltd., Invasion Energy Inc., Livingston Energy Ltd., Papier Masson Ltee. and Wave Energy Ltd.
Margaret A. McKenzie (1) (3) Calgary, Alberta	2007	Ms. McKenzie is the Chief Financial Officer of 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).
Geoffrey C. Merritt (4) Calgary, Alberta	2009	Mr. Merritt has been an independent businessman since April, 2009. Mr. Merritt was the founder of Masters Energy Inc., a public exploration and production company, incorporated in 2003 and acquired by us in April 2009. From 1998 to 2003, Mr. Merritt was the President and CEO of Sunfire Energy. Prior to 1998, Geoff was the Vice President and General Manager of the oil and gas division of Pembina Corporation. Mr. Merritt currently sits on the board of Perpetual Energy Inc.

Name and Municipality of Residence	Director Since	Principal Occupation
Jim Peplinski (2) (4) Calgary, Alberta	1997	Mr. Peplinski is the founder of Jim Peplinski Leasing Inc. (a commercial vehicle lessor). Mr. Peplinski is also the VP Business Development, Calgary Flames Hockey Club as well as an investor in real estate and oil and gas. Mr. Peplinski currently sits on the board of directors of Wrangler West Energy Corp.
J. Graham Weir (1) (4) Calgary, Alberta	2004	Mr. Weir is an independent businessman. From September 1990 to December 2000, he was Vice President and Director of Corporate Finance for Goepel McDermid Inc. (an investment bank), where he initiated and completed acquisition, financing, financial advisory, merger and valuation assignments for mid-market public and private companies generally headquartered in Calgary and active in the oil and gas producer and service sectors. Mr. Weir chairs the boards of Graymont Limited and Pulse Seismic Inc. and serves as a director of other companies including: Coral Hill Energy Ltd., Flagstone Energy Inc., Grupo Calidra, S.A. de C.V. and Joss Windpower Inc.
Grant A. Zawalsky (2) (3) Calgary, Alberta	2000	Mr. Zawalsky is a Partner of Burnet, Duckworth & Palmer LLP (Barristers and Solicitors). Mr. Zawalsky has been a Partner of Burnet, Duckworth & Palmer LLP since 1994. Mr. Zawalsky currently sits on the board of directors of a number of public and private companies including Endurance Energy Ltd., Flagstone Energy Inc., Home Quarter Resources Ltd., NuVista Energy Ltd., Range Royalty Management Ltd. (general partner of Range Royalty Limited Partnership), Spur Resources Ltd., Whitecap Resources Inc. and is Corporate Secretary of Bonavista Energy Corporation, Echoex Ltd., Northpoint Energy Ltd., RMP Energy Inc. and Rock Energy Ltd.

Notes:
(1) Member of our audit committee.
(2) Member of our compensation committee.
(3) Member of our governance and nominating committee.
(4) Member of our reserves committee.
(5) We do not have an executive committee.
(6) Directors hold office until the next annual meeting of Shareholders or until their successors are duly elected or appointed.

Officers

The name, municipality of residence, principal occupation for the prior five years and position (including with a predecessor of us), of each of our officers is as follows:

Name and Municipality of Residence	Officer Since	Office
Craig H. Hansen Calgary, Alberta	1992	President & Chief Executive Officer.
C.L. (Chuck) Buckley Calgary, Alberta	2010	Vice President, Geosciences since June, 2010; prior thereto, Vice President, Exploration of Highpine Oil & Gas Ltd., a public energy company.
Jason B. Dranchuk Calgary, Alberta	2006	Vice President, Finance and Chief Financial Officer; prior thereto, Vice President, Finance and Controller and before that Corporate Controller for Enserco Energy Service Company Inc. and Calfrac Well Services Ltd.
Tracy L. Howard Calgary, Alberta	2007	Corporate Secretary; prior thereto, Manager, Administration.
Brian G. Kergan Calgary, Alberta	2007	Vice President, Corporate Development since August, 2007; prior thereto, he held a business development role with West Energy Ltd, and before that held various engineering and management positions with Anderson Exploration and Devon Canada.
Kevin C.Y. Lee Calgary, Alberta	2009	Vice President, Alberta Plains North since September, 2009; prior thereto, Vice President, Engineering of Trafalgar Energy Ltd., a public energy company and before that he was Vice President of Engineering at Luke Energy.
Robert T. Moriyama Calgary, Alberta	2011	Vice President, Enhanced Recovery since January, 2011; prior thereto, he held various management and reservoir & exploitation engineering roles with Legacy Oil & Gas, Canera Resources, Pengrowth Corporation and Imperial Oil.
Randolph J. Doetzel Calgary, Alberta	2011	Vice President, Operations since June, 2011; prior thereto, our Production Manager, Williston Basin since January, 2009. Prior thereto, he held various executive, management and engineering positions at Cobalt Energy, Harvest Operations, Apache Canada, and Samson Canada. Randy has both domestic and international field experience during his time with NEFT Services (Russia) and Norcen Energy.

As at March 12, 2012, our directors and officers, as a group, beneficially owned, controlled or directed, directly or indirectly, 1,920,689 Common Shares or approximately 6.5 percent of our issued and outstanding Common Shares.

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 our control 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, other than Mr. Zawalsky who was a director of Efficient Energy Resources Ltd. (a private electrical generation company), which agreed to the voluntary appointment of a receiver in 2005. In addition, none of our directors or executive officers (nor any personal holding company of any such persons), or shareholder holding a sufficient number of our securities to materially affect the control of us 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.

In addition, 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, 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 that 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 the *Business Corporations Act* (Alberta). To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate of our audit committee is attached hereto as Schedule "C". The members of our audit committee are Kyle D. Kitagawa, Margaret A. McKenzie and J. Graham Weir.

Composition of the Audit Committee

The members of our audit committee are independent (in accordance with National Instrument 52-110 – *Audit Committees*) and are financially literate.

Relevant Education and Experience

Name	Relevant Education and Experience
Kyle D. Kitagawa *(Audit Committee Chairman)*	Mr. Kitagawa has been an independent businessman since 2003. In addition, Mr. Kitagawa serves as Chairman of Canadian Energy Services & Technology Corp. and Coral Hill Energy Ltd. and is also a director of ProspEx Resources Ltd. Prior directorships include Advanced Mobile Power Systems, LLC, Esprit Exploration Ltd., Ferus Trust, Independent Energy Ltd., Invasion Energy Inc., Livingston Energy Ltd., Papier Masson Ltee. and Wave Energy Ltd. Mr. Kitagawa holds a Master of Business Administration degree from Queen's University, a Bachelor of Commerce from the University of Calgary and is a Chartered Accountant.
Margaret A. McKenzie	Ms. McKenzie is 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 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. Ms. McKenzie is on the board of directors of Bonavista Energy Corporation and three private oil and natural gas exploration and development companies (Spur Resources Ltd., Endurance Energy Ltd. and Home Quarter Resources Ltd.).
J. Graham Weir	Mr. Weir is an independent businessman. From September 1990 to December 2000, he was Vice President and Director of Corporate Finance for Goepel McDermid Inc. (an investment bank), where he initiated and completed acquisition, financing, financial advisory, merger and valuation assignments for mid-market public and private companies generally headquartered in Calgary and active in the oil and gas producer and service sectors. Mr. Weir chairs the boards of Graymont Limited and Pulse Seismic Inc. and serves as a director of other companies including: Coral Hill Energy Ltd., Flagstone Energy Inc., Grupo Calidra, S.A. de C.V. and Joss Windpower Inc. Mr. Weir graduated from Trent University in 1974 with a Bachelors Degree in Mathematics and the University of Manitoba in 1977 with a Masters Degree in Actuarial Mathematics. Mr. Weir received the designation Chartered Business Valuator in 1994 and completed a Masters Degree in Mathematical Finance at the University of Oxford in 2005.

Pre-Approval Policies and Procedures

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

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditors, including expenses, in each of the last two fiscal years for audit services were $206,275 in 2011 and $239,725 in 2010.

International Financial Reporting Standards Fees

The aggregate fees billed in each of the last two fiscal years for assurance related services by our external auditor, including expenses, 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 $Nil in 2011 and $83,625 in 2010. The 2010 fees specifically related to procedures on our International Financial Reporting Standards ("**IFRS**") opening balance sheet and our IFRS 2010 quarters performed by our auditors.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by our external auditors, including expenses for tax compliance, tax advice and tax planning were $213,452 in 2011 and $329,601 in 2010.

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 $54,078 in 2011 and $11,150 in 2010.

DIVIDENDS

We currently make monthly dividend payments to our Shareholders on the 15th day of each month or the first business day following the 15th day. The record date for any dividend is the last business day of the month preceding the dividend date or such other date as may be determined by our Board of Directors. In accordance with stock exchange rules, an ex-dividend date occurs two trading days prior to the record date to permit time for settlement of trades of securities and dividends must be declared a minimum of seven trading days before the record date. Unless otherwise indicated, all dividends paid or to be paid on our Common Shares are designated as "eligible dividends" for Canadian income tax purposes.

In connection with the Arrangement, our prior Distribution Reinvestment Plan was amended and restated as a Dividend Reinvestment Plan. Canadian Shareholders who participate in the Dividend Reinvestment Plan are entitled to reinvest monthly cash dividends in additional Common Shares. At our discretion, the additional Common Shares will be issued from treasury at a 95 percent of the weighted average trading price of our Common Shares for the five days prior to the dividend payment date or acquired at prevailing market rates with no discount.

Dividends can and may fluctuate in the future. Actual 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. Our Board of Directors cannot provide assurance that cash flow will be available for distribution to Shareholders in the amounts anticipated or at all. See "*Risk Factors*".

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.

Our ability to make cash dividends to Shareholders may be directly or indirectly affected in certain events as a result of certain restrictions, including restrictions set forth in our Credit Facility and the solvency tests in the *Business Corporations Act* (Alberta). In particular, dividends may be only declared and paid to Shareholders if: (i) no default or event of default shall have occurred or shall occur as a result of making any such dividends; and (ii) no borrowing base shortfall shall have occurred that is continuing.

The following monthly cash dividends have been declared by us or the Trust for each of the three most recently completed financial years:

For the Month Ended	Dividends per Common Share	Payment Date
January 31, 2011	$0.14	February 15, 2011
February 28, 2011	$0.14	March 15, 2011
March 31, 2011	$0.14	April 15, 2011
April 30, 2011	$0.14	May 16, 2011
May 31, 2011	$0.14	June 15, 2011
June 30, 2011	$0.14	July 15, 2011
July 31, 2011	$0.14	August 15, 2011
August 31, 2011	$0.14	September 15, 2011
September 30, 2011	$0.14	October 17, 2011
October 31, 2011	$0.10	November 15, 2011
November 30, 2011	$0.10	December 15, 2011
December 31, 2011	$0.10	January 16, 2012
Total	$1.56	

For the Month Ended	Distributions per Trust Unit	Payment Date
January 31, 2010	$0.18	February 15, 2010
February 28, 2010	$0.18	March 15, 2010
March 31, 2010	$0.18	April 15, 2010
April 30, 2010	$0.18	May 17, 2010
May 31, 2010	$0.18	June 15, 2010
June 30, 2010	$0.18	July 15, 2010
July 31, 2010	$0.18	August 16, 2010
August 31, 2010	$0.18	September 15, 2010
September 30, 2010	$0.18	October 15, 2010
October 31, 2010	$0.18	November 15, 2010
November 30, 2010	$0.18	December 15, 2010
December 31, 2010	$0.18	January 17, 2011
Total	$2.16	

For the Month Ended	Distributions per Trust Unit	Payment Date
January 31, 2009	$0.18	February 16, 2009
February 28, 2009	$0.18	March 16, 2009
March 31, 2009	$0.18	April 15, 2009
April 30, 2009	$0.18	May 15, 2009
May 31, 2009	$0.18	June 15, 2009
June 30, 2009	$0.18	July 15, 2009
July 31, 2009	$0.18	August 17, 2009
August 31, 2009	$0.18	September 15, 2009
September 30, 2009	$0.18	October 15, 2009
October 31, 2009	$0.18	November 16, 2009
November 30, 2009	$0.18	December 15, 2009
December 31, 2009	$0.18	January 15, 2010
Total	$2.16	

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "ZAR". The Common Shares commenced trading on the TSX 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 TSX for the periods indicated.

Period	High	Low	Volume
2011			
January (7 to 31)	22.35	20.19	1,313,836
February	24.00	20.65	1,303,583
March	24.25	21.75	2,194,118
April	23.69	21.55	1,391,060
May	22.51	21.00	980,183
June	21.94	20.32	885,883
July	21.95	19.25	1,224,238
August	20.13	16.30	2,404,320
September	17.19	12.66	2,913,185
October	14.19	10.54	4,323,854
November	13.27	12.85	2,121,689
December	14.20	12.40	1,766,079
2012			
January	15.16	13.64	1,308,826
February	15.99	14.50	1,266,529
March (1 - 12)	15.24	14.20	444,896

In connection with the Arrangement, holders of Trust Units and Exchangeable Shares exchanged their Trust Units and Exchangeable Shares for Common Shares. Prior to the Arrangement, the Trust Units and Exchangeable Shares were listed and traded on the TSX. The trading symbol for the Trust Units was ZAR.UN and for the Exchangeable Shares was ZOG.B.

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 and upgrading, 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, Saskatchewan and Manitoba, all of which should be carefully considered by investors in the oil and 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 in western Canada.

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, 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.

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 m^3/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.

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. As yet, Manitoba does not have natural gas production in commercial quantities and does not therefore impose such export restrictions.

Pipeline Capacity

From time to time, pipeline operators will limit the amount of product shipped. A typical reason may be limited ability for purchasers to accept product or there have been limitations imposed due to a pipeline taken out of service for planned or unplanned outages.

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. 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 NAFTA 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 oil sands projects, 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, 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 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010.

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, the maximum royalty payable under the royalty regime was set at 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/m^3 compared to the previous royalty curve.

Royalty rates for natural gas under the royalty regime 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 royalty regime was set at 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 Alberta's royalty regime. Prior to payout of an oil sands project, 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 per barrel 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. In addition, concurrently with the implementation of the New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the current royalty regime.

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 gas.

The Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, has the stated objectives of increasing recovery from oil and 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 provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008 and are intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres 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 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. 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 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 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 five-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 program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. 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. One aspect of the program was a drilling royalty credit program which provided up to a $200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. Another aspect of the program was a new well royalty program which provided for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated "volume cap" was reached. The *New Well Royalty Regulation*, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011.

In addition to the foregoing, the Government of Alberta has implemented certain 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; and

- 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 per hectare, 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 metres and horizontal wells with a true vertical depth greater than 2,300 metres;

- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres 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 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres 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 m^3 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 m^3 during the first 12 production months and average daily production less than 23 m^3 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 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

- *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 m^3 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 gas areas. In 2009, 2010 and 2011, the Government of British Columbia awarded $120 million in royalty credits to oil and 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. 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 metres. 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 Crown royalty or freehold production tax 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 m^3 for third and fourth tier oil and $50 per m^3 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 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 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 gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to

October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of gas for every m^3 of oil, and new 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 gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* replacing the existing *Freehold Oil and Gas Production Tax Act* with the intention 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 legislation, although several regulations remain in force under the previous legislation.

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 m^3 for third and fourth tier gas and $35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old 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 gas, 35% for third tier and new gas, and 45% for old 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 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres 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 m^3 for qualifying exploratory 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 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- *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 m^3 for horizontal gas wells;

- *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; and

- *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.

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.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards which are designed to reduce emissions resulting for the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards is set to commence on July 1, 2012 for new wells and facilities licensed on or after such date, and to apply to existing licensed wells and facilities on July 1, 2015.

Manitoba

In Manitoba, the royalty amount payable on oil produced from Crown lands depends on the classification of the oil produced as "old oil" (produced from a well drilled prior to April 1, 1974 that does not qualify as new oil or third tier oil), "new oil" (oil that is not third tier oil and is produced from a well drilled on or after April 1, 1974 and prior to April 1, 1999, from an abandoned well re-entered during that period, from an old oil well as a result of an enhanced recovery project implemented during that period, or from a horizontal well), "third tier oil" (oil produced from a vertical well drilled after April 1, 1999, an abandoned well re-entered after that date, an inactive vertical well activated after that date, a marginal well that has undergone a major workover, or from an old oil well or a new oil well as a result of an enhanced recovery project implemented after that date), or "holiday oil" (oil that is exempt from any royalty or tax payable). Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order from the Minister. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations.

Royalties payable on natural gas production from Crown lands are equal to 12.5% of the volume of natural gas sold, calculated for each production month.

Producers of oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale based on the monthly production volume and the classification of oil as old oil, new oil, third tier oil and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated per production month. There is no freehold production tax payable on gas consumed as lease fuel.

The Government of Manitoba maintains a Drilling Incentive Program (the "**Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no Crown royalties or freehold production taxes are payable until the holiday oil volume has been produced. Holiday oil volumes must be produced within ten (10) years of the finished drilling date or the completion date of a major workover. Wells drilled for injection, or converted to injection wells, in an approved enhanced recovery project, earn one (1) year holiday for portions of the project area. Under the Program, wells drilled for purposes of injection (or wells converted to injection prior to producing predetermined volumes of oil) in an approved enhanced oil recovery project earn a one-year holiday for portions of the project area.

The Program consists of the following components, such components being subject to additional considerations under the *Crown Royalty and Incentives Regulation*:

- *New Well Incentive* provides licensees of newly drilled, non-horizontal wells drilled prior to January 1, 2014 with a holiday oil volume to a maximum of 10,000 m^3;

- *Deep Drilling Incentive* provides licensees who drill a well to a total depth sufficient to penetrate the Devonian Duperow formation with a holiday oil volume of up to 20,000 m^3, and licensees who drill a well deeper than the Devonian Three Forks formation can make a one-time assignment of up to 10,000

m^3 of holiday oil volume earned through previous drilling or major workovers to such well's holiday oil volume;

- *Horizontal Well Initiative* provides licensees of horizontal wells drilled prior to January 1, 2014 with a holiday oil volume of 10,000 m^3, and the first horizontal leg (unless otherwise approved) drilled from an existing horizontal well on or after January 1, 2009 and prior to January 1, 2014 and more than one (1) year after the finished drilling date of the well), will earn an additional holiday royalty volume of 3,000 m^3;

- *Marginal Well Major Workover Incentive* provides licensees of marginal wells where a major workover is completed prior to January 1, 2014 with a holiday oil volume of 500 m^3, with a marginal oil well defined as an abandoned well or a well that was either not operated over the previous 12 months or produced oil at an average rate of less than 1 m^3 per operating day; and

- *Injection Well Incentive* provides a one year exemption from the payment of Crown royalties or freehold production taxes on production allocated to a unit tract in which a well is drilled or converted to water injection;

Further, holiday oil volumes earned by a newly drilled well or a marginal well that has undergone a major workover can be transferred to a Holiday Oil Volume Account at the request of the licensee, the purpose of which is to optimize the value of holiday oil volumes earned by providing a company with the flexibility of allocating holiday oil volumes earned among new wells.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments, with the exception of Manitoba where approximately 80% of crude oil and natural gas rights in the southwestern portion of the province are privately owned. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to exploration reservations and leases for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Rights to explore for and produce oil and natural gas from privately held lands are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba 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.

Alberta also has 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. 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. The order in which these agreements will receive reversion notices will depend on their vintage and location, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and will revisit the decision in spring 2012.

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 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be deemed to be legislative instruments equivalent to regulations and will be 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, leases, 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.

On August 29, 2011 the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the "**Revised LARP**") updating its prior draft of April 5, 2011 (the "**Draft LARP**"). The Revised LARP, while establishing several conservation areas of the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas. However, references to the cancellation of existing tenures have been removed from the Revised LARP and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

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 although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol.

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 CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 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:

(a) 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 CO_2 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.

(b) 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.

(c) Under the Updated Action Plan, regulated entities were 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. However, with the recent withdrawal from the Kyoto Protocol, the future use of this mechanism may not occur.

(d) 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.

From December 7 to 18, 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to 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. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. 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 that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity 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.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it will issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

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 CO_2 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.

We do not own or have a working interest in facilities that meet or are expected to exceed these emissions thresholds.

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.

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 current tax level is $25 per tonne of CO_2 equivalent. It is scheduled to increase to $30 per tonne of CO_2 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 partially came 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. 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 CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed offsets and emissions trading are currently in the consultation stage.

We do not own or have a working interest in facilities that are subject to these reporting or 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.

Manitoba

The Government of Manitoba has indicated its intention to commence public consultations with respect to the development of a cap and trade system to reduce GHG emissions; however no legislation with respect to the same is currently in effect in Manitoba.

RISK FACTORS

An investment in our Common 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.

You should carefully consider the following risk factors, as well as the other information contained in this Annual Information Form and our other public filings before making an investment decision. 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 " – C*ertain 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 including ongoing credit and liquidity concerns, the actions of OPEC, sanctions imposed on certain oil producing nations by other countries, 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 may, therefore, affect the amount of dividends that we pay to our Shareholders.

The economics of producing from some wells may change as a result of lower commodity prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of our reserves. We might also elect not to produce from certain wells at lower prices. Volatile oil and natural gas prices also 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 evaluator.

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 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 and other financial systems 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 Credit Agreement may be extended prior to June 27, 2012 and failure to extend may, and higher rates will, adversely affect our financial condition

Our existing Credit Agreement and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our existing Credit Agreement 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. Our current Credit Agreement includes credit facilities in the maximum principal amount of $180 million. Our current Credit Agreement has a term date of June 27, 2012 and may be extended for a further 364-day period at our request. If the credit facilities are not extended, they convert to a 365-day term loan and are repayable in full at the end of such term. Repayment of all outstanding amounts under the Credit Agreement may be demanded on relatively short notice if an event of default occurs, which is continuing. 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 Agreement will not be extended for the same amount or on the same terms.

We are required to comply with covenants under the Credit Agreement. In the event that we do not comply with these covenants, which may be affected by events beyond our control, 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. The lenders under the Credit Agreement have security over all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default, such as breach of our financial covenants, the lenders under the Credit Agreement may foreclose on or sell our working interests in our properties.

Our borrowing base is determined and re-determined by our lenders based on our reserves, commodity prices, applicable discount rate and other factors as determined by our lenders. A material decline in commodity prices could reduce our borrowing base, thereby reducing the funds available to us under our credit facilities which could result in a portion, or all, of our bank indebtedness being required to be repaid.

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 our Credit Agreement may also limit dividends. Although we believe the Credit Agreement 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 security issuances, 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 gas reserves additional Common Shares may be issued. Additionally, from time to time we may issue Common Shares 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 Common Shares. 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 our Credit Agreement, 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 are 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, 2011, our income statement reflected $0.8 million of unrealized losses 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 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 (including hydraulic fracturing), 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. Drilling hazards or environmental damage could greatly increase the cost of operations (including hydraulic fracturing), 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 consequently, 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.

Hydraulic fracturing is subject to certain risks

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (natural gas and oil) production. The use of hydraulic fracturing is being used to produce commercial quantities of natural gas and oil from reservoirs that were previously unproductive. We use hydraulic fracturing extensively in our operations. With the increase in the use of fracture stimulations in horizontal wells there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology as it relates to the environment. This increased attention to fracture stimulations may result in increased regulation or changes of law which may make the conduct of our business more expensive or prevent us from conducting our business as currently conducted. Any new laws, regulation or permitting requirements regarding hydraulic fracturing could lead to operational delays or increased operating costs or third party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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

The oil and natural 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 the 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 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 oil and gas industry could reduce demand for crude oil and natural gas, increase our costs, or delay or restrict our operations, all 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 natural gas industry, such as resource allowance, may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders. Tax authorities having jurisdiction over us or our 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, Saskatchewan, Manitoba and the United States, 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 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 McDaniel, 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 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 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 McDaniel 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 McDaniel and such variations could be material. The McDaniel 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, NGLs and natural gas and they are substituted for the price assumptions utilized in the McDaniel 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 McDaniel 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 McDaniel Report will be reduced, in future years, to the extent that such activities do not achieve the level of success assumed in the McDaniel Report.

Estimates of proved and probable oil and gas reserves include undeveloped reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is still required before such wells begin production. Reserves may be recognized when plans are in place to make the required investments to convert these undeveloped reserves to producing. Circumstances such as a sustained decline in commodity prices or poorer than expected results from initial activities could cause a change in the investment or development plans which could result in a material change in our reserves estimates.

Proved and probable oil and gas reserves include undeveloped reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is still required before such wells begin production. Reserves may be recognized when plans are in place to make the required investments to convert these undeveloped reserves to producing. Circumstances such as a sustained decline in commodity prices or poorer than expected results from initial activities could cause a change in the investment or development plans which could result in a material change in our reserves estimates.

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 are estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

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 hazards, 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. 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, the shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. 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 13.7 percent of our properties are operated by third parties, based on daily production. Our return on assets operated by others depends 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. 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 or processing capacity;
- operational problems affecting pipelines and facilities;
- 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 availability, proximity and capacity of oil and natural gas pipelines and processing and storage facilities and government regulations, including regulations relating to environmental protection, royalties, allowable production, pricing, taxes, 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*".

The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems

We deliver our products through gathering, processing and pipeline systems some of which we do not own. Access to the pipeline capacity for the transport of crude oil into the United States has become inadequate for the amount of Canadian production being exported to the United States and has recently resulted in significantly lower amounts being realized by Canadian producers compared with the WTI price for crude oil. The lack of access to capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition.

Certain pipeline leaks in 2011 have gained media and other stakeholder attention and may result in additional regulation or changes in law which could impede the conduct of our business or make our operations more expensive.

A portion of our production may, from time to time, be processed through facilities owned by third parties and which we do not have control of. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuance or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale.

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 natural gas industry

There are numerous companies in the oil and natural 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 related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities.

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 availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or our ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- 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 gas production and development in the Western Canadian Sedimentary Basin and the United States. In the future, we may acquire oil and 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 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 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 purchase of significant resource assets, such reviews cannot guarantee that an unforeseen defect in the chain of title will not arise to defeat our title to certain assets. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties that we control that, if successful or made into law, could impair our activities on them and result in a reduction in 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, commodity prices, 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 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 *Income Tax Act* (Canada) 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

Except for contracts entered into in the ordinary course of business, the only material contract entered into by us within the most recently completed financial year, or before the most recently completed financial year but which is still material and is in effect, is our Credit Agreement in respect of our $180 million syndicated credit facilities, which agreement is described in Note 11 to our annual audited consolidated financial statements for the year ended December 31, 2011, which note is incorporated by reference herein. Copies of each of these documents have been filed on SEDAR at *www.sedar*.com.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we are or were 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 our Common 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 our directors and senior officers, any holder of Common Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10 percent of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the last three financial years or during the current financial year which has materially affected or would materially affect us.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement 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 NI 51-102 by us during, or related to, our most recently completed financial year other than McDaniel, our independent engineering evaluator, and Ernst & Young LLP, our auditors. None of the principals of McDaniel had 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. Ernst & Young LLP is independent in accordance with the Rules of Professional Conduct as outlined by 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 that Grant A. Zawalsky, one of our directors, is a partner at Burnet, Duckworth & Palmer LLP, which is a law firm that 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.zargon.ca.* 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 12, 2012 relating to our annual Shareholders meeting to be held on April 25, 2012. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2011 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:

Zargon Oil & Gas Ltd.
700, 333 – 5th Avenue S.W.
Calgary, Alberta, T2P 3B6
Tel: (403) 264-9992
Fax: (403) 265-3026

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

(Form 51-101F3)

Management of Zargon Oil & Gas Ltd. ("**Zargon**") is responsible for the preparation and disclosure of information with respect to Zargon's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

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

The Reserves Committee of the board of directors of Zargon has

(a) reviewed Zargon'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 has reviewed Zargon's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

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

(e) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(f) 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) C.H. Hansen
President and Chief Executive Officer

(signed) B.G. Kergan
Vice President, Corporate Development

(signed) J.G. Weir
Director and Chairman of the Reserves Committee

(signed) J. Peplinski
Director and Member of the Reserves Committee

(signed) K.D. Kitagawa
Director and Member of the Reserves Committee

(signed) G.C. Merritt
Director and Member of the Reserves Committee

February 15, 2012

APPENDIX B

REPORT ON RESERVES DATA BY MCDANIEL

(Form 51-101F2)

To the board of directors of Zargon Oil & Gas Ltd. ("**Zargon**"):

1. We have evaluated Zargon's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

2. The reserves data are the responsibility of Zargon'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 Zargon evaluated by us for the year ended December 31, 2011, and identifies the respective portions thereof that we have evaluated and reported on to Zargon's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue (thousands before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	February 15, 2012	Canada	$nil	$500,955	$nil	$500,955
		United States	$nil	$58,042	$nil	$58,042

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 report referred to in paragraph 4 for events and circumstances occurring after their respective preparation date.

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

Executed as to our report referred to above:

(signed) McDaniel & Associates Consultants Ltd.
Calgary, Alberta
February 15, 2012

APPENDIX C

MANDATE & TERMS OF REFERENCE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "Committee") is a committee of the Board of Directors (the "Board") of Zargon Oil & Gas Ltd. ("Zargon" or the "Corporation") 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 of director approval, the audited financial statements and other mandatory disclosure releases containing financial information, and review of the annual reserves. The objectives of the Committee are as follows:

1. To assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of Zargon and related matters;

2. To provide better communication between directors and external auditors;

3. To enhance the external auditor's independence;

4. To increase the credibility and objectivity of financial reports; and

5. 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

1. The Committee shall be comprised of at least three (3) directors of Zargon, none of whom are members of management of Zargon and all of whom are "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110").

2. The Board shall have the power to appoint the Committee Chairman.

3. 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

4. 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.

5. 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.

6. 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.

7. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the board.

8. 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

9. 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.

10. It is the responsibility of the Committee to satisfy itself on behalf of the board with respect to Zargon's Internal Control Systems:

- identifying, monitoring and mitigating business risks; and

- ensuring compliance with legal, ethical and regulatory requirements.

11. It is a primary responsibility of the Committee to review the annual financial statements of Zargon prior to their submission to the board of directors for approval. The process should include but not be limited to:

- reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' 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 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; and

- obtain explanations of significant variances with comparative reporting periods.

12. 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 Zargon's disclosure of all other financial information and shall periodically access the accuracy of those procedures.

13. With respect to the appointment of external auditors by the board, the Committee shall:

- recommend to the board the appointment of the external auditors;

- recommend to the board the terms of engagement of the external auditor, including the compensation of the auditors and a 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.

14. Review with external auditors (and internal auditor if one is appointed by Zargon) their assessment of the internal controls of Zargon, 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 Zargon and its subsidiaries.

15. The Committee must pre–approve all non–audit services to be provided to Zargon 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.

16. The Committee shall review on an annual basis the reserves as evaluated by the external reserve evaluators. As part of this review, the Audit Committee shall be represented by at least one member at a reserve committee face-to-face meeting with management and the reserve evaluators.

17. The Committee shall review risk management policies and procedures of Zargon (i.e. hedging, litigation and insurance).

18. The Committee shall establish a procedure for:

    - the receipt, retention and treatment of complaints received by Zargon regarding accounting, internal accounting controls or auditing matters; and

    - the confidential, anonymous submission by employees of Zargon of concerns regarding questionable accounting or auditing matters.

19. The Committee shall review and approve Zargon's hiring policies regarding employees and former employees of the present and former external auditors of Zargon.

20. The Committee shall have the authority to investigate any financial activity of Zargon. All employees of Zargon are to cooperate as requested by the Committee.

21. The Committee may retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at the expense of Zargon without any further approval of the board.