2013 Annual Information Form

March 20, 2014

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GLOSSARY OF TERMS

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

Entities

Board of Directors means the board of directors of Whitecap.

Compass means Compass Petroleum Ltd.

Invicta means Invicta Energy Corp.

Home Quarter means Home Quarter Resources Ltd.

Midway means Midway Energy Ltd.

Onyx means Onyx 2006 Inc.

Shareholders means holders of our Common Shares.

Spitfire means Spitfire Energy Inc.

Spry means Spry Energy Ltd.

Whitecap, **we**, **us, our** or the **Corporation** means Whitecap Resources Inc.

Independent Engineering

COGE Handbook means Canadian Oil and Gas Evaluation Handbook.

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

Home Quarter Report means the report prepared by Sproule and dated September 20, 2013 evaluating the crude oil, natural gas and natural gas liquids attributable to Home Quarter as at September 30, 2013.

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

McDaniel Report means the report prepared by McDaniel dated February 26, 2014 evaluating the crude oil, natural gas, natural gas liquids and sulphur reserves attributable to all of our oil and natural gas assets as at December 31, 2013.

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

NI 51-102 means National Instrument 51-102 – *Continuous Disclosure Obligations.*

Sproule means Sproule Associates Limited.

Share and Loan Capital

Common Shares means our common shares, as presently constituted.

Credit Facility means collectively our extendible revolving credit facility and term loan facility with a syndicate of lenders.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Bbls/d	barrels per day	Bcf	billion cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	thousand stock tank barrels of oil	MMbtu	million British Thermal Units
NGLs	natural gas liquids	GJ	gigajoule

Other

AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
$Cdn	Canadian dollars
m^3	cubic metres
MBoe	thousand barrels of oil equivalent.
MMBoe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
$000s	thousands of dollars
$MM	millions of dollars

CONVERSIONS

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	28.317
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

CONVENTIONS

Certain terms used herein are defined in the "*Glossary of Terms*". Certain other terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form, including documents incorporated by reference herein, contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking statements relate to future events or our future performance. All information and statements other than statements of historical fact contained in this Annual Information Form are forward-looking statements. Such forward-looking statements may be identified by looking for words such as "about", "approximately", "may", "believe", "expects", "will", "intends", "should", "could", "plan", "budget", "predict", "potential", "projects", "anticipates", "forecasts", "estimates", "continues" or similar words or the negative thereof or other comparable terminology. In addition, there are forward-looking statements in this Annual Information Form under the headings: "*General Development of Our Business – Recent Developments*" with respect to our plans and focus, including with respect to the asset acquisition, the disposition, the private company acquisition, the offering and the dividend increase; the estimated purchase price of the asset acquisition; the estimated proceeds from the disposition; the estimated proceeds from the offering; and the anticipated closing dates for asset acquisition, the disposition, the offering and the private company acquisition; "*General Description of Our Business – Stated Business Objectives and Strategy*" as to our business plan and strategy; "*General Description of Our Business – Cyclical and Seasonal Impact of Industry*" as to the impact of our price risk management programs; "*General Description of Our Business – Environmental Policies*" with respect to our expectations regarding abandonment and reclamation costs; "*General Development of Our Business – Renegotiation or Termination of Contracts"* as to our expectations relating to the effect of the renegotiation or termination of our contracts or subcontracts in the remainder of 2014; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data*" as to our reserves and future net revenue from our reserves, income taxes and pricing, exchange and inflation rates; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data*" as to the development of our proved undeveloped reserves and probable undeveloped reserves, future developments costs, our plans to fund future development costs through a combination of internally generated cash flow, debt and equity issuances and anticipated funding costs; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information*" as to our exploration and development focus, plans and opportunities, anticipated land expiries, hedging and marketing policies, abandonment and reclamation obligations, tax horizon and future production; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Changes to Reserves Data – Home Quarter Assets*" as to the reserves and future net revenue from the reserves of Home Quarter, income taxes and pricing, exchange and inflation rates, future development costs, our plans to fund future development costs through internally generated funds and production estimates; and "*Dividend Policy*" as to our dividend policy and the future payment of dividends.

In addition to the forward-looking statements identified above, this Annual Information Form contains forward-looking statements pertaining to the following:

- waterflood implementation opportunities and the results therefrom;
- recovery factors;
- well completions and the timing thereof;
- the performance characteristics of our oil and natural gas properties;
- expectation of future production rates, volumes and product mixes;
- projections of market prices and costs, and exchange and inflation rates;
- supply and demand for oil and natural gas;
- expectations regarding our ability to raise capital and to continually add to reserves through acquisitions, development and optimization;
- treatment under governmental regulatory regimes and tax laws;

- productive capacity of wells, anticipated or expected production rates and anticipated dates of commencement of production and timing of results therefrom;
- fluctuations in depletion, depreciation and accretion rates;
- expected changes in regulatory regimes in respect of royalty curves and regulatory improvements and the effects of such changes;
- plans to expand recovery from certain of our properties; and
- our business plans and strategy.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this Annual Information Form. Although we believe that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking statements contained herein include the following:

- volatility in market prices for oil and natural gas and foreign exchange rates;
- operational risks and liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuation in foreign exchange or interest rates;
- stock market volatility;
- environmental risks;
- the inability to access sufficient capital from internal and external sources;
- changes in general economic, market and business conditions;
- the accuracy of oil and gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- the uncertainties in regard to the timing of our exploration and development program;
- fluctuations in the costs of borrowing;
- political or economic developments;
- ability to obtain regulatory and other third party approvals;
- the occurrence of unexpected events;
- the results of litigation or regulatory proceedings that may be brought against us;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "*Risk Factors*".

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding, among other things: the timing of obtaining regulatory approvals; completion of the asset acquisition, the disposition and the private company acquisition; commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; access to capital; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; and future operating costs.

We have included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes.

You are further cautioned that the preparation of financial statements in accordance with generally accepted accounting principles in Canada requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available and as the economic environment changes. **The information contained in this Annual Information Form, including the documents incorporated by reference herein, identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Information Form are made as of the date of this Annual Information Form and we undertake no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

BARREL OF OIL EQUIVALENCY

The term "Boe" may be misleading, particularly if used in isolation. A Boe conversion ratio of six thousand cubic feet of natural gas to barrels of oil (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. **Given 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 Mcf: 1 Bbl, utilizing a conversion ratio at 6 Mcf: 1 Bbl may be misleading as an indication of value**.

NON-GAAP MEASURES

Within this Annual Information Form, references are made to terms commonly used in the oil and natural gas industry. The term "netback" in this Annual Information Form is not a recognized measure under generally accepted accounting principles in Canada. We use "netback" as a key performance indicator and it is used by us in operational and capital allocation decisions. It is determined by deducting royalties and operating expenses from petroleum and natural gas revenue. Readers are cautioned; however, that this measure should not be construed as an alternative to net earnings or cash flow from operating activities determined in accordance with generally accepted accounting principles in Canada as an indication of our performance.

WHITECAP RESOURCES INC.

General

We are the resulting entity following the completion of the reverse takeover of Spitfire and subsequent amalgamation with Spitfire on July 1, 2010 to form "Whitecap Resources Inc."

Spitfire was incorporated under the *Business Corporations Act* (Alberta) on August 30, 2001. On November 6, 2001, Spitfire amended and restated its articles to change its authorized share structure to include an unlimited number of common shares and an unlimited number of preferred shares. On March 31, 2004, Spitfire amalgamated pursuant to the *Business Corporations Act* (Alberta) with its wholly-owned subsidiary, Cashel Resources Inc. to form the amalgamated corporation, Spitfire Energy Ltd. On April 1, 2005, Spitfire purchased all of the issued and outstanding shares of, and then amalgamated with a private oil and gas company, Spitfire Exploration Ltd. pursuant to the *Business Corporations Act* (Alberta) to form Spitfire.

We were incorporated under the *Business Corporations Act* (Alberta) on June 3, 2008 as "1405340 Alberta Ltd.". On September 2, 2008, we amended our articles to change our name from 1405340 Alberta Ltd. to "Whitecap Resources Inc." and we commenced operations on September 17, 2009.

On October 15, 2010, we filed articles of amendment to effect a consolidation of our Common Shares on a basis of 10 pre-consolidated shares for every 1 Common Share. The consolidation was approved by our Shareholders at our annual general and special meeting held on September 14, 2010.

Subsequent to each acquisition of other corporate entities acquired by us since our inception, we have amalgamated the resulting subsidiary into Whitecap. We filed articles of amalgamation and amalgamated with respect to these acquisitions:

Date of Amalgamation	Name of Amalgamated Subsidiary
July 1, 2010	Spitfire
July 30, 2010	Onyx
April 20, 2011	Spry
February 10, 2012	Compass
April 23, 2012	Midway
April 30, 2013	Invicta
January 6, 2014	Home Quarter

Our head office is located at Suite 500, 222 – 3rd Avenue S.W., Calgary, Alberta, T2P 0B4 and our registered office is located at Suite 2400, 525 - 8th Avenue S.W. Calgary, Alberta, T2P 1G1. We do not have any subsidiaries.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

Since inception, we have grown from a junior, privately held, oil and gas company to a publicly traded, dividend paying, oil-weighted company focused on providing sustainable monthly dividends to our Shareholders and per share growth through a combination of accretive oil-based acquisitions and organic growth on existing and acquired assets.

The following provides a summary of how our business has developed over the last three years.

Developments in 2011

On January 14, 2011 we closed the acquisition of light oil weighted properties located in our core Valhalla North property for the purchase price of $50 million. Pursuant to an area of mutual interest with a joint venture partner, our joint venture partner elected to participate in this acquisition such that we and our joint venture partner jointly purchased these assets, each as to an undivided 50% interest and paid 50% of the $50 million purchase price (being $25 million each). For further information with respect to this acquisition, see our business acquisition report relating to the acquisition, which is available on our SEDAR profile at *www.sedar.com*.

On April 20, 2011 we acquired all of the issued and outstanding common shares of Spry for approximately $130.9 million in cash and the issuance of an aggregate of 8,228,023 Common Shares. We also assumed the debt and working capital of Spry, estimated at $36.0 million as at March 1, 2011. The acquisition of Spry was partially funded through the issuance of 22,000,000 subscription receipts at a price of $6.80 per subscription receipt for gross proceeds of $149.6 million. Concurrent with the closing of the acquisition of Spry on April 20, 2011, the subscription receipts were exchanged for Common Shares. For further information with respect to the Spry acquisition, see our business acquisition report relating to the acquisition, which is available on our SEDAR profile at *www.sedar.com*.

Developments in 2012

On February 10, 2012 we acquired all of the issued and outstanding common shares of Compass for $14.0 million in cash and the issuance of an aggregate of 10.9 million Common Shares. We also assumed the positive working capital of Compass, estimated at $1.3 million (net of transaction costs) as at November 30, 2011. In connection with the acquisition of Compass, the borrowing base of the Credit Facility was increased from $190 million to

$250 million. For further information with respect to the Compass acquisition, see our business acquisition report relating to the acquisition, which is available on our SEDAR profile at *www.sedar.com*.

On April 20, 2012 we completed the acquisition of all of the issued and outstanding class A common shares of Midway for $111.35 million in cash and the issuance of an aggregate of 32.09 million Common Shares and also assumed Midway's debt and working capital deficit, estimated at $132.4 million at April 20, 2012. In connection with the acquisition, we also assumed the obligations of Midway in respect of Midway's previously outstanding share purchase warrants issued in February 2012. As a result, each previously outstanding warrant to acquire a class A common share of Midway entitled the holder thereof to acquire 0.4802 of a Common Share at a price of $4.00 per 0.4802 of a Common Share ($8.33 per whole Common Share). All of these warrants that were outstanding on February 15, 2013 have expired in accordance with their terms.

The acquisition of Midway was partially funded through a bought deal public financing of 5,941,000 units issued at a price of $20.20 per unit for gross proceeds of approximately $120 million. Each unit was comprised of one subscription receipt at a price of $10.10 per subscription receipt and one Common Share at a price of $10.10 per Common Share. Concurrent with the closing of the acquisition of Midway on April 20, 2012, the subscription receipts were exchanged for Common Shares. For further information with respect to the Midway acquisition, see our business acquisition report relating to the acquisition which is available on our SEDAR profile at *www.sedar.com*.

Concurrent with the closing of the Midway acquisition the borrowing base of our Credit Facility was increased to $400 million from $250 million.

On October 25, 2012 we entered into various agreements to sell certain of our non-core oil and natural gas assets in the Swan Hills area of Alberta and certain heavy oil assets in Alberta for total cash proceeds of approximately $28.6 million, prior to adjustments. In conjunction therewith, we increased the borrowing base of our Credit Facility to $450 million from $400 million.

On November 20, 2012 our Board of Directors adopted our dividend policy of paying monthly dividends at a rate of $0.05 per Common Share per month commencing January 2013. The first dividend payment occurred in February 2013.

Developments in 2013

On April 30, 2013 we completed the acquisition of all of the issued and outstanding shares of Invicta in exchange for $219,324 in cash and 4,832,188 Common Shares. We also assumed Invicta's net debt of approximately $17.4 million after accounting for transaction costs.

On May 9, 2013 we increased the borrowing base of our Credit Facility to $520 million from $450 million.

On May 16, 2013 we completed a public offering of 10,393,000 Common Shares, for gross proceeds of approximately $100 million. In addition, on May 16, 2013 we completed a private placement financing of "flow-through" Common Shares for gross proceeds of $20 million. The proceeds from the offerings were used to fund the purchase price of an acquisition of certain assets in the Dodsland area of Saskatchewan which was completed on May 22, 2013. Total consideration for the acquisition was $110 million in cash not including customary post closing adjustments.

On June 27, 2013 our Board of Directors approved a 5 percent increase to our monthly dividend to $0.0525 per Common Share starting with the October 2013 dividend payable in November 2013.

On July 31, 2013 we completed an acquisition of various oil weighted assets located primarily in the Valhalla and Garrington areas of Alberta for the aggregate purchase price of approximately $173.6 million. A portion of the purchase price of the acquisition was funded from the net proceeds of a bought deal public offering of 17,172,000 subscription receipts issued at a price of $9.90 per subscription receipt for aggregate gross proceeds of approximately $170 million. The offering of subscription receipts closed on July 18, 2013 and the subscription receipts were exchanged for Common Shares on July 31, 2013 contemporaneously with the closing of the acquisition.

On October 15, 2013 we increased the borrowing base of our Credit Facility to $600 million from $520 million.

On October 28, 2013 we announced that we had completed the acquisition of a Cardium light oil property and a working interest consolidation of our Eagle Lake Viking unit for total consideration of approximately $90 million.

On November 13, 2013 we completed a public offering of 5,417,000 Common Shares at a price of $12.00 per Common Share for aggregate gross proceeds of approximately $65 million.

Recent Developments

Home Quarter Acquisition

On January 6, 2014 we closed the acquisition of all of the issued and outstanding shares of Home Quarter in exchange for the issuance of 27,534,255 Common Shares and assumed Home Quarter's $3.0 million working capital surplus. For further information with respect to the acquisition of Home Quarter, see our business acquisition report relating to the acquisition which is available on our SEDAR profile at *www.sedar.com*.

Asset Acquisition

On March 14, 2014, we entered into an asset purchase and sale agreement to acquire certain strategic light oil assets focused primarily in our Pembina Cardium / west central core area, as well as at Boundary Lake in northeast British Columbia, which is located just northwest of our core Valhalla area for net consideration of $692.7 million (after completing the disposition of certain Nisku natural gas production and related facilities to an unrelated third party and taking into account estimated purchase price adjustments at closing). Completion of the asset acquisition is subject to customary closing conditions including the accuracy of representations and warranties and the performance of covenants, and receipt of regulatory approvals. The asset acquisition is expected to close on or about May 1, 2014 with an effective date of November 1, 2013. See "*General Development of our Business – Recent Developments – The Disposition*" below.

Disposition

On March 14, 2014, we entered into a purchase and sale agreement with an unrelated third party to sell certain Nisku natural gas production and related facilities which we will acquire pursuant to the asset acquisition. The disposition of these assets is expected to close concurrently with or shortly after the asset acquisition and is subject to the completion of the asset acquisition and various other customary closing conditions. The proceeds from the disposition are anticipated to be approximately $113 million.

Offering

On March 17, 2014 we entered into an agreement with a syndicate of underwriters, pursuant to which the underwriters have agreed to purchase for resale to the public, on a bought deal basis 44,643,333 subscription receipts at a price of $11.20 per subscription receipt. The gross proceeds of the offering will be held in escrow pending completion of the asset acquisition. If all outstanding conditions to the completion of the asset acquisition have been obtained on or before June 30, 2014, the net proceeds from the sale of the subscription receipts will be released from escrow to us and each subscription receipt will be exchanged for one of our Common Shares for no additional consideration. The net proceeds of the offering will be used to fund a portion of the net purchase price of the asset acquisition. If the asset acquisition is not completed by June 30, 2014 or upon such later date within fifteen (15) days as the underwriters may elect, then the purchase price for the subscription receipts will be returned to subscribers, together with their *pro rata* portion of the interest earned on the escrowed funds. Completion of the offering is subject to certain conditions including the receipt of all necessary regulatory approvals, including the approval of the Toronto Stock Exchange. Closing of the offering is expected to occur on April 8, 2014.

Private Company Acquisition

On March 14, 2014 we entered into a purchase and sale agreement for the acquisition of a privately held oil and gas company. The purchase price for the private company acquisition is approximately $107 million and is expected to close on or before April 30, 2014. The private company is not related to or conditional upon the acquisition or the disposition and is not significant for us.

Dividend Increase

Provided that the asset acquisition closes, our Board of Directors has approved a 10% increase to our monthly dividend from $0.0567 to $0.0625 per share ($0.75 per share annualized). Based on the anticipated closing of the asset acquisition of early May 2014, the dividend increase is expected to start with the May 2014 dividend payable in June 2014. We believe this is a conservative dividend increase that is sustainable long-term. See "*Dividend Policy*" and "*Risk Factors*".

Significant Acquisitions

During the year ended December 31, 2013 we did not complete any significant acquisitions for which a business acquisition report would be required to be filed under Part 8 of NI 51-102.

The completion of the acquisition of Home Quarter on January 6, 2014 constituted a significant acquisition under Part 8 of NI 51-102. We filed a business acquisition report regarding the acquisition of Home Quarter on March 20, 2014, which is incorporated by reference into this Annual Information Form and available on our SEDAR profile at *www.sedar.com*.

GENERAL DESCRIPTION OF OUR BUSINESS

Stated Business Objectives and Strategy

Our business plan is to deliver profitable growth to our Shareholders over the long term under varying business conditions. Since inception we have executed our business plan by pursuing strategic acquisitions and carrying out development programs focusing on our core properties in the Peace River Arch area of Northwest Alberta, Deep Basin area of Northwest Alberta, West central Alberta and Saskatchewan. Once a property has been acquired, we pursue optimization and ongoing development and expansion opportunities.

We are focused on providing sustainable monthly dividends and per share growth through a combination of accretive oil-based acquisitions and organic growth on existing and acquired assets.

The key attributes to our dividend growth strategy are as follows:

- provide sustainable dividends and per share growth in production, reserves and cash flow;
- conservative payout ratio and strong balance sheet;
- strong capital efficiencies in concentrated areas;
- predictable and stable production base;
- large light oil development drilling inventory; and
- disciplined and value focused management team.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition are dependent on the prices received for our 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 – Prices, Markets and Marketing*" and "*Risk Factors – Hedging*".

Ongoing Acquisition and Disposition Activities

Potential Acquisitions

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

Potential Dispositions

We evaluate potential dispositions of our oil and natural gas assets as part of our ongoing asset portfolio management program. In addition, we evaluate potential farm-out opportunities with other industry participants in respect of our oil and natural gas assets in circumstances where we believe it is prudent to do so based on, among other things, our capital program, development plan timelines and the risk profile of such assets. We are normally in the process of evaluating several potential dispositions of our assets and farm-out opportunities at any one time, which individually or together could be material.

Environment Policies

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

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

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

We expect to incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2013, expenditures for normal compliance with environmental regulations as well as expenditures for above normal compliance were not material.

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 2014 by the renegotiation or termination of contracts or subcontracts other than with respect to our Credit Facility which has an annual renewal date in May 2014. See "*Risk Factors – Credit Facility Arrangements*".

Competitive Conditions

We are a member of the petroleum industry, which is highly competitive at all levels. We compete with other companies for all of our business inputs, including exploration and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. See "*Risk Factors – Competition*".

We strive to be competitive by maintaining financial flexibility and by utilizing current technologies to enhance optimization, development and operational activities.

Human Resources

At December 31, 2013, we employed 67 full-time employees, including 62 office and 5 field employees.

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below is dated February 26, 2014. The statement is effective as of December 31, 2013 and the preparation date of the statement is February 26, 2014. The Report Of Management and Directors On Oil and Gas Disclosure in Form 51-101F3 and the Report On Reserves Data By Independent Qualified Reserves Evaluator in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by McDaniel with an effective date of December 31, 2013 as 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, not including the impact of any price risk management activities. 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.

On January 6, 2014 we completed the acquisition of Home Quarter. Unless otherwise noted, all information given in this Annual Information Form does not include land, production or reserves attributable to Home Quarter. For details regarding the assets acquired pursuant to the Home Quarter acquisition see: "*Statement of Reserves Data and Other Oil and Natural Gas Information – Changes to Reserves Data – Home Quarter Assets*".

All of our reserves are in Canada and, specifically, in the Provinces of Alberta and Saskatchewan.

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 estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after tax valuation. 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. Our financial statements for the year ended December 31, 2013 should be consulted for additional information regarding our taxes.

All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the McDaniel Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. 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. The recovery and reserve estimates on our properties described herein are estimates only. The actual reserves on our properties may be greater or less than those calculated. See "*Risk Factors*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED:								
Developed Producing	31,592.2	26,299.9	167.8	146.5	98,238.9	82,639.7	4,846.6	3,457.4
Developed Non-Producing	308.7	265.0	-	-	4,018.4	3,604.8	37.1	24.7
Undeveloped	27,664.3	24,105.0	-	-	59,169.1	52,218.8	3,058.4	2,381.6
TOTAL PROVED	59,565.2	50,669.9	167.8	146.5	161,426.4	138,463.3	7,942.1	5,863.7
PROBABLE	22,425.8	18,224.4	57.8	48.8	72,021.5	60,911.5	3,355.3	2,382.3
TOTAL PROVED PLUS PROBABLE	81,991.0	68,894.3	225.6	195.3	233,447.9	199,374.8	11,297.4	8,246.1

	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)	Unit Value Before Income Tax Discounted at 10% per Year $/Boe
PROVED:						
Developed Producing	2,176,334	1,589,930	1,257,990	1,048,239	904,737	23.74
Developed Non-Producing	22,743	13,885	10,300	8,300	6,983	10.14
Undeveloped	1,395,254	885,735	603,071	430,497	317,230	14.86
TOTAL PROVED	3,594,331	2,489,550	1,871,361	1,487,037	1,228,950	19.79
PROBABLE	1,828,336	859,420	495,332	326,762	235,692	13.09
TOTAL PROVED PLUS PROBABLE	5,422,667	3,348,970	2,366,693	1,813,799	1,464,642	17.87

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	1,906,087	1,412,343	1,131,072	951,902	828,309
Developed Non-Producing	17,390	10,314	7,553	6,032	5,033
Undeveloped	1,036,801	638,293	416,131	280,335	191,427
TOTAL PROVED	2,960,278	2,060,951	1,554,755	1,238,269	1,024,769
PROBABLE	1,362,522	637,891	365,583	239,459	171,323
TOTAL PROVED PLUS PROBABLE	4,322,800	2,698,841	1,920,338	1,477,728	1,196,092

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS (1)(2)

RESERVES CATEGORY	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Total Proved	7,357,742	1,118,886	1,817,676	767,123	59,726	3,594,331	634,053	2,960,278
Total Proved plus Probable	10,849,980	1,751,743	2,766,514	839,810	69,247	5,422,666	1,099,867	4,322,800

Notes:
(1) Total revenue includes company revenue before royalty and includes other income.
(2) Royalties include Crown, freehold and overriding royalties and mineral tax.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE (1) ($/Bbl)	($/Mcf)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	1,841,410.1	20.2	-
	Heavy Oil (including solution gas and other by-products)	3,817.4	21.7	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	26,133.5	-	1.43
	Total	1,871,361.0		
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	2,322,786.2	18.3	-
	Heavy Oil (including solution gas and other by-products)	4,903.0	20.7	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	38,791.9	-	1.22
	Coalbed Methane (including by-products)	212.3	-	-
	Total	2,366,693.4		

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

Definitions and Notes to Reserves Data Tables

In the tables set forth above in "*Reserves Data (Forecast Prices and Costs)*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "**Gross**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

   (b) in relation to wells, the total number of wells in which we have an interest; and

   (c) in relation to properties, the total area of properties in which we have an interest.

2. "**Net**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves;

   (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

   Reserve Categories

   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

   (a) analysis of drilling, geological, geophysical and engineering data;

   (b) the use of established technology; and

   (c) specified economic conditions (see the discussion of "*Economic Assumptions*" below).

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

   (a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   (b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

   "**Economic Assumptions**" are the forecast prices and costs used in the estimate.

   Development and Production Status

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

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

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

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

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, 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.

Levels of Certainty for Reported Reserves

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

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

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

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

4. "**Exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

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

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

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

6. "**Development well**" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

7. "**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

8. "**Service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

9. **"Forecast Prices and Costs"**

These are prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

10. Numbers may not add due to rounding.

11. The estimates of future net revenue presented in the tables above do not represent fair market value.

12. We do not have any synthetic oil or other products from non-conventional oil and gas activities other than an immaterial amount from four probable coal bed methane undeveloped well locations.

Pricing Assumptions

The forecast cost and price assumptions in this statement assume primarily 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, inflation and exchange rates utilized in the McDaniel Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS [(1)]

	OIL				NATURAL GAS	NATURAL GAS LIQUIDS	NATURAL GAS LIQUIDS		
Year	**WTI Cushing Oklahoma ($US/Bbl)**	**Edmonton Par Price 40° API ($Cdn/ Bbl)**	**Hardisty Bow River 25° API ($Cdn/ Bbl)**	**Hardisty Heavy 12° API ($Cdn/ Bbl)**	**AECO Gas Price ($Cdn/ MMbtu)**	**Edmonton Propane ($Cdn/Bbl)**	**Edmonton Butane ($Cdn/Bbl)**	**INFLATION RATES %/Year [(2)]**	**EXCHANGE RATE ($US/$Cdn) [(3)]**
Forecast									
2014	95.00	95.00	77.90	67.50	4.00	50.20	76.60	2.0	0.950
2015	95.00	96.50	81.10	70.40	4.25	50.50	77.80	2.0	0.950
2016	95.00	97.50	81.90	71.20	4.55	50.60	78.60	2.0	0.950
2017	95.00	98.00	82.30	71.50	4.75	51.30	79.00	2.0	0.950
2018	95.30	98.30	82.60	71.80	5.00	52.00	79.20	2.0	0.950
2019	96.60	99.60	83.70	72.70	5.25	53.20	80.30	2.0	0.950
2020	98.50	101.60	85.30	74.20	5.35	54.10	81.90	2.0	0.950
2021	100.50	103.60	87.00	75.60	5.45	55.20	83.50	2.0	0.950
2022	102.50	105.70	88.80	77.20	5.55	56.30	85.20	2.0	0.950
2023	104.60	107.90	90.60	78.80	5.65	57.40	87.00	2.0	0.950
2024	106.70	110.00	92.40	80.30	5.75	58.50	88.60	2.0	0.950
2025	108.80	112.20	94.20	81.90	5.90	59.80	90.40	2.0	0.950
2026	111.00	114.50	96.20	83.60	6.00	61.00	92.30	2.0	0.950
2027	113.20	116.70	98.00	85.20	6.15	62.20	94.00	2.0	0.950
2028	115.50	119.10	100.00	86.90	6.25	63.50	96.00	2.0	0.950

Notes:
(1) As at January 1, 2014.
(2) Inflation rate for costs.
(3) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by us for the year ended December 31, 2013, excluding price risk management activities, were $3.36/Mcf for natural gas, $90.09/Bbl for light and medium crude oil, and $49.42/Bbl for NGLs.

Reserves Reconciliation

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Gross Proved (Mbbls)	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**	**Gross Proved (Mbbls)**	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**
December 31, 2012	37,168.1	15,656.3	52,824.4	120.2	43.2	163.4
Discoveries	-	-	-	-	-	-
Extensions	8,973.5	2,935.4	11,908.9	-	-	-
Infill Drilling	-	-	-	-	-	-
Improved Recovery	942.0	283.5	1,225.5	-	-	-
Technical Revisions	512.4	(1,853.2)	(1,340.8)	74.6	14.5	89.1
Acquisitions	17,474.1	5,876.6	23,350.7	-	-	-
Dispositions	(1,148.4)	(472.7)	(1,621.1)	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(4,356.4)	-	(4,356.4)	(27.0)	-	(27.0)
December 31, 2013	59,565.3	22,425.8	81,991.1	167.8	57.8	225.6

	ASSOCIATED AND NON-ASSOCIATED GAS[(1)]			NATURAL GAS LIQUIDS		
	Gross Proved (MMcf)	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**	**Proved (Mbbls)**	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**
December 31, 2012	111,395.9	52,231.3	163,627.2	5,035.1	2,155.5	7,190.5
Discoveries	-	-	-	-	-	-
Extensions	23,787.8	10,651.0	34,438.8	1,087.1	537.3	1,624.4
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	6,840.0	(3,428.9)	3,411.1	723.3	5.0	728.3
Acquisitions	34,026.0	12,907.2	46,933.2	1,754.6	671.5	2,426.1
Dispositions	(831.6)	(339.0)	(1,170.6)	(34.5)	(14.1)	(48.6)
Economic Factors	-	-	-	-	-	-
Production	(13,791.7)	-	(13,791.7)	(623.4)	-	(623.4)
December 31, 2013	161,426.4	72,021.5	233,447.9	7,942.1	3,355.3	11,297.4

Note:

(1) Includes solution gas volumes and coal bed methane gas volumes.

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 some cases, it will take longer than two years to develop these reserves. 99% of our proved undeveloped reserves are in our core areas where we are actively spending capital to develop those properties. As such, we expect that the large majority of our booked undeveloped projects will be completed within a two year time frame. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

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

Year	**Light and Medium Oil (Mbbls)**		**Heavy Oil (Mbbls)**		**Natural Gas (MMcf)**		**NGLs (Mbbls)**	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior	1,587.4	1,587.4	2.7	2.7	4,968.2	4,968.2	132.0	132.0
2011	6,112.0	7,699.4	118.4	121.1	3,648.3	8,616.5	101.7	233.7
2012	7,349.8	15,049.2	-	-	26,288.2	34,904.7	1,607.1	1,840.8
2013	12,615.1	27,664.3	-	-	24,264.4	59,169.1	1,217.6	3,058.4

The majority of our proved undeveloped reserves evaluated in the McDaniel Report are attributable to our Valhalla, Deep Basin, Garrington, Pembina, and Lucky Hills properties. Proved undeveloped reserves have been assigned in areas where the reserves can be estimated with a high degree of certainty. In most instances, proved undeveloped reserves will be assigned on lands immediately offsetting existing producing wells within the same accumulation or pool. McDaniel has assigned 40.6 MMboe of proved undeveloped reserves in the McDaniel Report with $763.2 million of associated undiscounted capital, of which $436.5 million is forecast to be spent in the first 2 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 the most recent three financial years and, in the aggregate, before that time.

Year	**Light and Medium Oil (Mbbls)**		**Heavy Oil (Mbbls)**		**Natural Gas (MMcf)**		**NGLs (Mbbls)**	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior	2,015.0	2,015.0	1.4	1.4	5,588.4	5,588.4	133.3	133.3
2011	2,940.9	4,955.9	93.9	95.3	1,527.9	7,116.3	38.5	171.8
2012	2,935.8	7,891.7	-	-	15,090.8	22,207.1	756.5	928.3
2013	3,381.6	11,273.3	-	-	11,184.1	33,391.2	610.5	1,538.8

Probable undeveloped reserves have been assigned in areas where the reserves can be estimated with less certainty. It is equally likely that that the actual remaining quantities recovered will be greater or less than the proved plus probable reserves. In most instances probable undeveloped reserves have been assigned on lands in the area with existing producing wells but there is some uncertainty as to whether they are directly analogous to the producing accumulation or pool. McDaniel has assigned 18.4 MMboe of probable undeveloped reserves in the McDaniel Report with $68.8 million of associated undiscounted capital, of which $31.4 million is forecast to be spent in the first 2 years.

Significant Factors or Uncertainties

We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

Future Development Costs

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

	FORECAST PRICES AND COSTS	
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2014	207,430.3	223,745.8
2015	231,403.7	247,049.9
2016	223,632.5	254,852.3
2017	51,199.0	51,523.8
2018	50,622.1	57,380.0
Remaining	2,835.6	5,258.0
Total (Undiscounted)	767,123.2	839,809.8

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity issuances. 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 could have a negative impact on our future cash flow.

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

Other Oil and Natural Gas Information

Principal Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2013. Information in respect of current production is average production, net to our working interest, except where otherwise indicated.

Peace River Arch

The Valhalla North property is located in the Peace River Arch area of Alberta and is characterized by shallow declines and a predictable production base. The primary reservoir that we are currently focused on is the Montney Sexsmith oil pool and associated waterflood. The key characteristics of the pool are light 36^{o} API oil, homogeneous reservoir quality and no original moveable water formation. Development to expand the waterflood to the entire pool as well as offsetting pool extensions is underway.

Deep Basin

The Deep Basin properties, which include Karr and Elmworth, are located southwest of Grande Prairie, Alberta. The primary reservoir being developed is the Dunvegan, which is primarily light sweet (38^{o} - 40^{o} API) oil. The Dunvegan is characterized by a thick oil column with significant oil in place per unit area. This area is being developed with horizontal multi-fracture wells that exhibit a lower decline profile than many areas due to the significant oil in place.

West Central Alberta

Our Cardium producing properties are located in East Pembina, Ferrier, Garrington and the Willesden Green areas of West central Alberta. The key characteristics of the Cardium are light 40^{o} API oil with geology and oil resource mapping that is well defined with legacy vertical wells. There is no significant mobile formation water in the Cardium which leads to a predictable production decline profiles.

West Central Saskatchewan

The primary reservoir that we are currently focused on developing is the Viking resource oil play. The key characteristics of this play is light 36^{o} API oil, predictable geology and production profiles as well as consistent and repeatable economics.

The Lucky Hills area is located in West central Saskatchewan and is characterized by prolific horizontal grassroots oil development with quick payouts and a predictable high netback production profile. The Eagle Lake property is characterized by predictable low decline waterflood supported production from primarily legacy vertical wells. Additional development is ongoing through the drilling of infill horizontal wells and reactivation of the waterflood to increase reserve recoveries.

Southwest Saskatchewan

This project is located at Fosterton in Southwest Saskatchewan and consists of Roseray and Cantuar oil pools. The key characteristics of these pools include medium 22^{o} API oil, stable and predictable low decline production profile and consistent and repeatable economics. Development and expansion of the waterflood in this area is a primary fous.

Oil And Natural Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2013.

	OIL WELLS				NATURAL GAS WELLS			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	576	487.0	116	94.7	85	78.4	239	157.4
Saskatchewan	691	572.4	104	85.2	6	4.8	23	17.9
Total	1,267	1,059.4	220	179.9	91	83.2	262	175.3

Of the non-producing wells, none were wells drilled in 2013 that were capable of production and had reserves assigned to them. In addition, as of the date of this Annual Information Form, none of these wells have been placed on production.

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2013.

	UNDEVELOPED ACRES		DEVELOPED ACRES		TOTAL ACRES	
	Gross	Net	Gross	Net	Gross	Net
Alberta	176,010	132,943	228,615	167,823	404,625	300,766
Saskatchewan	82,334	63,736	39,034	32,697	121,368	96,433
Total	258,344	196,679	267,649	200,520	525,994	397,199

Rights to explore, develop and exploit 32,227 net acres of these undeveloped land holdings could expire by December 31, 2014 if not continued.

When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by us to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties.

We may use certain financial instruments to hedge exposure to commodity price fluctuations on a portion of our crude oil and natural gas production. For further information, see note 5 to our financial statements for the year ended December 31, 2013. See "*Risk Factors – Hedging*".

Additional Information Concerning Abandonment and Reclamation Costs

Our overall abandonment and reclamation costs are based on well bore abandonment and reclamation costs and liability issues such as flare pit remediation, facility decommissioning, remediation and reclamation costs. These costs were estimated using our experience conducting abandonment and reclamation programs. We review suspended or standing well bores for reactivation, recompletion or sale and conduct systematic abandonment programs for those well bores that do not meet our criteria. A portion of our liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder issues, and opportunities for multi-location programs to reduce costs.

As at December 31, 2013 we had 1,861 net wells for which we expect to incur abandonment and reclamation costs.

The total amount of abandonment and reclamation costs that we expect to incur, net of estimated salvage values, 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, 2013	69,247.1	9,969.5
Anticipated to be paid in 2014	718.8	716.0
Anticipated to be paid in 2015	31.2	27.8
Anticipated to be paid in 2016	536.1	439.2

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 surface leases, facilities and pipelines. The McDaniel Report only deducted $69.3 million (undiscounted) and $10.0 million (10% discount) for abandonment costs of wells with proved and probable reserves, in estimating the future net revenues disclosed in this Annual Information Form.

Tax Horizon

Based on our recent developments and estimated pro-forma 2014 cash flow and capital expenditures, we do not expect to be cash taxable in 2014. See "*General Development of our Business – Recent Developments*."

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2013.

Expenditure	Year Ended December 31, 2013 ($000s)
Property acquisition costs – Unproved properties (1)	3,291
Property acquisition costs – Proved properties (2)	371,820
Corporate acquisition costs	66,450
Exploration costs (3)	689
Development costs (4)(5)	182,780
Other	3,340
Total	628,370

Notes:
(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Net of dispositions.
(3) Geological and geophysical capital expenditures and drilling costs for exploration wells.
(4) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells.
(5) Net of drilling credits.

Exploration and Development Activities

The following table sets forth the gross development wells in which we participated during the year ended December 31, 2013. We did not participate in any exploratory wells during the year.

	Development	
	Gross	Net
Natural Gas	1	0.8
Light and Medium Oil	99	72.5
Dry	-	-
Total	100	73.3

In 2014, we expect to drill approximately 50 oil wells in Alberta and 120 oil wells in Saskatchewan.

Finding and Development Costs

The following table summarizes our finding and development costs for the periods indicated.

($/Boe) (1)(2)(3)	2013	2012	2011	Three Year Average
Proved Reserves				
Finding, development and acquisition cost	23.36	27.78	27.90	24.68
Finding and development costs	20.62	22.74	24.13	24.51
Acquisition costs	25.37	32.24	31.55	28.59
Proved plus Probable Reserves				
Finding, development and acquisition cost	18.31	20.94	20.80	18.67
Finding and development costs	17.21	18.07	17.83	19.59
Acquisition costs	19.02	23.31	23.56	21.27

Notes:
(1) Including changes in future development capital expenditures.
(2) We have presented finding and development costs 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.
(3) 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 capital expenditures generally will not reflect total finding and development costs related to reserves additions for that year.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2014, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained above under the subheading "*Disclosure of Reserves Data*".

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (Boe/d)
Total Proved					
Deep Basin	984	-	1,850	122	1,414
Garrington	3,533	-	13,605	1,049	6,849
Greater Pembina	3,439	-	10,900	384	5,640
West Central Saskatchewan	4,032	-	6,359	180	5,271
Peace River Arch	2,134	-	9,667	329	4,075
South West Saskatchewan	870	-	937	6	1,031
Minors	73	-	3,635	16	695
Total	15,064	-	46,953	2,086	24,975
Total Proved plus Probable					
Deep Basin	1,084	-	2,027	135	1,557
Garrington	3,563	-	13,786	1,063	6,923
Greater Pembina	3,501	-	11,117	392	5,746
West Central Saskatchewan	4,419	-	6,960	196	5,775
Peace River Arch	2,199	-	10,272	350	4,261
South West Saskatchewan	927	-	948	6	1,091
Minors	80	-	4,866	17	909
Total	15,774	-	49,977	2,158	26,262

Production History

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

	Quarter Ended 2013				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2013
Average Daily Production [1]					
Light and Medium Oil (bbls/d)	11,085	10,912	12,870	12,585	11,870
Natural Gas Liquids (bbls/d)	1,319	1,500	1,864	2,159	1,713
Gas (MMcf/d)	31,126	32,983	40,281	43,902	37,117
Combined (boe/d)	17,592	17,909	21,448	22,061	19,769
Average Net Production Prices Received					
Light and Medium Oil ($/bbl)	84.77	88.47	102.26	83.32	90.09
Natural Gas Liquids ($/bbl)	51.60	41.13	49.70	53.57	49.42
Gas ($/Mcf)	3.38	3.79	2.60	3.74	3.36
Combined ($/boe)	63.32	64.62	70.62	60.20	64.73
Royalties Paid					
Light and Medium Oil ($/bbl)	10.00	11.73	13.75	12.49	12.09
Natural Gas Liquids ($/bbl)	8.03	6.82	7.94	10.81	8.63
Gas ($/Mcf)	0.10	0.23	0.12	0.14	0.15
Combined ($/boe)	7.09	8.14	9.17	8.46	8.28
Production Costs [2][3][4]					
Light and Medium Oil ($/bbl)	17.22	17.19	15.66	17.61	16.89
Natural Gas Liquids ($/bbl)	-	-	-	-	-
Gas ($/Mcf)	4.25	4.69	4.12	6.01	4.35
Combined ($/boe)	12.96	12.70	11.42	12.54	12.36
Netback Received					
Light and Medium Oil ($/bbl)	57.55	59.55	72.85	53.23	61.11
Natural Gas Liquids ($/bbl)	43.57	34.31	41.76	42.76	40.79
Gas ($/Mcf)	(0.97)	(1.13)	(1.65)	(2.41)	(1.14)
Combined ($/boe)	43.27	43.78	50.03	39.20	44.09

Notes:

(1) Before the deduction of royalties.
(2) Production costs are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between product types.
(3) Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.
(4) Production costs attributable to natural gas liquids have been included in the light and medium oil and natural gas production cost amounts.

The following table indicates our average daily production (including production from our major areas) for the year ended December 31, 2013.

	Crude Oil (Bbls/d)	Natural Gas Liquids (Bbls/d)	Natural Gas (Mcf/d)	BOE (Boe/d)
Deep Basin	272	28	502	384
Garrington	2,994	886	10,888	5,694
Greater Pembina	3,038	386	9,893	5,073
West Central Saskatchewan	3,117	121	4,172	3,933
Peace River Arch	1,561	282	8,240	3,216
South West Saskatchewan	559	-	803	693
Other	329	10	2,619	776
Total	11,870	1,713	37,117	19,769

Changes to Reserves Data

Home Quarter Assets

On January 6, 2014 we closed the acquisition of all of the issued and outstanding shares of Home Quarter, an oil-weighted energy company located in Calgary, Alberta with operations primarily in the Kindersley (Whiteside) area of west central Saskatchewan which immediately offsets our lands and Viking production in Kindersley (Lucky Hills).

The reserves data set forth below is based upon the report prepared by Sproule dated September 20, 2013 with an effective date of September 30, 2013. The Home Quarter Report summarizes the crude oil, natural gas liquids and natural gas reserves of Home Quarter and the net present values of future net revenue for these reserves using forecast prices and costs as at September 30, 2013. The Home Quarter Report was prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Home Quarter engaged Sproule to provide an evaluation of proved and proved plus probable reserves as at September 30, 2013.

All of Home Quarter's reserves at September 30, 2013 were in Canada and specifically in the province of Saskatchewan. Estimates of reserves and the related future net revenue presented below have an effective date of September 30, 2013. The reserves information is based on certain factual data supplied by Home Quarter and the opinion of Sproule of reasonable practice in the industry. Our management did not participate in the preparation of the Home Quarter Reserves Report.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Home Quarter's 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.

Reserves and Future Net Revenue Data (Forecast Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES
AS OF SEPTEMBER 30, 2013
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		NATURAL GAS LIQUIDS		NATURAL GAS		TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mboe)	Net (Mboe)
PROVED								
Developed Producing	2,616.2	2,341.8	64.2	54.9	6,032	5,195	3,685.7	3,262.1
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	2,858.1	2,568.1	30.8	27.6	4,387	3,940	3,620.0	3,252.3
TOTAL PROVED	5,474.2	4,909.9	94.9	82.5	10,419	9,132	7,305.7	6,514.3
PROBABLE	4,573.2	4,114.7	65.6	58.2	7,445	6,671	5,879.5	5,284.8
TOTAL PROVED PLUS PROBABLE	10,047.4	9,024.6	160.5	140.8	17,864	15,803	13,185.2	11,799.1

NET PRESENT VALUES OF FUTURE NET REVENUE
BEFORE INCOME TAXES DISCOUNTED (%/year)
AS OF SEPTEMBER 30, 2013
FORECAST PRICES AND COSTS

RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
PROVED					
Developed Producing	167,903	141,822	123,728	110,540	100,536
Developed Non-Producing	-	-	-	-	-
Undeveloped	115,911	86,891	66,969	52,730	42,193
TOTAL PROVED	283,813	228,713	190,697	163,271	142,729
PROBABLE	261,062	180,917	133,759	103,775	83,469
TOTAL PROVED PLUS PROBABLE	544,875	409,630	324,456	267,045	226,198

TOTAL FUTURE NET REVENUE ($000s)
(UNDISCOUNTED)
AS OF SEPTEMBER 30, 2013
FORECAST PRICES AND COSTS

Reserves Category	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	CAPITAL DEVELOPMENT COSTS ($000s)	ABANDONMENT AND RECLAMATION COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)
Total Proved	590,147	72,253	158,706	68,762	6,613	283,813
Total Proved Plus Probable	1,103,920	132,320	296,240	120,744	9,741	544,875

Notes:

(1) Total revenue includes company revenue before royalty and includes other income.
(2) Royalties include Crown, freehold and overriding royalties and mineral tax.

Pricing Assumptions

The forecast cost and price assumptions assume the continuance of current laws and regulations and increases in wellhead selling prices, and take into account inflation with respect to future operating and capital costs. In the Home Quarter Report operating and capital costs are assumed to escalate at 1.5% per annum beginning in 2014**.** The foreign exchange rate incorporated by Sproule in the Home Quarter Report was US$0.99/C$1.00 and the crude oil and natural gas base case prices were Sproule's August 31, 2013 pricing forecast, which were as follows:

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Oil Price ($C/bbl)	AECO Gas Price ($/mmbtu)	Pentanes Plus FOB Edmonton ($/bbl)	Butanes F.O.B. Edmonton ($/bbl)
2013	104.44	105.49	2.81	117.86	58.97
2014	96.33	97.30	3.50	108.71	54.39
2015	89.61	90.52	3.74	101.13	50.60
2016	89.23	90.14	4.15	100.70	50.39
2017	96.96	97.93	4.80	109.42	54.75
2018	98.41	99.40	4.88	111.06	55.57
2019	99.89	100.89	4.95	112.72	56.40
2020	101.38	102.41	5.03	114.41	57.25
2021	102.91	103.94	5.12	116.13	58.11
2022	104.45	105.50	5.20	117.87	58.98
2023	106.02	107.09	5.28	119.64	59.86
2024	107.61	108.69	5.37	121.44	60.76

During the nine months ended September 30, 2013, Home Quarter received the following weighted average prices in respect of its production: natural gas - $2.87/Mcf; crude oil - $95.53/bbl; and natural gas liquids - $48.30/bbl. The overall weighted average price received by Home Quarter on a combined oil equivalent basis was $77.08/Boe.

Future Development Costs

The following table sets forth development costs deducted in the estimation of Home Quarter's future net revenue attributable to the reserve categories noted below:

Year	Total Proved ($000s)	Total Proved Plus Probable Reserves ($000s)
2013	10,746.8	12,451.0
2014	41,321.0	51,999.9
2015	16,694.3	56,292.8
2016	-	-
Thereafter	-	-
Total Undiscounted	68,762.1	120,743.7
10% Discounted	56,462.1	96,587.8

Whitecap expects that the capital listed in the preceding table will be funded through internally generated funds flow and will not have any associated funding costs. Therefore, the capital commitments will not affect the disclosed reserves of future net revenue.

Production Estimates

The following table sets out the volumes of working interest production before royalties, using forecast prices and costs, estimated for the period of October 1, 2013 to December 31, 2013 in the Home Quarter Report which is reflected in the estimate of future net revenue disclosed in the tables above.

	Light Oil (Bbls/d)	**Heavy Oil (Bbls/d)**	**Natural Gas (Mcf/d)**	**Natural Gas Liquids (Bbls/d)**	**Boe (Boe/d)**
Total Proved	2,772.1	-	5,495.0	59.4	3,757.1
Total Proved plus Probable	3,085.8	-	5,997.9	64.2	4,160.0

Production History

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

	Quarter Ended		
	Sept. 30, 2013	**June 30, 2013**	**Mar. 31, 2013**
Average Daily Production[1]			
Light and Medium Crude Oil (bbl/d)	2,153	1,440	1,390
Gas (Mcf/d)	4,158	2,576	2,191
NGLs (bbl/d)	33	28	29
Combined (BOE/d)	2,878	1,897	1,785
Average Price Received			
Light and Medium Crude Oil ($/bbl)	103.58	91.32	87.08
Gas ($/Mcf)	2.36	3.51	3.11
NGLs ($/bbl)	53.52	43.73	46.71
Combined ($/BOE)	81.48	74.73	72.32
Royalties Paid			
Light and Medium Crude Oil ($/bbl)	11.97	11.31	11.16
Gas ($/Mcf)	0.42	0.62	0.57
NGLs ($/bbl)	5.15	10.81	9.28
Combined ($/BOE)	10.98	10.80	10.69
Operating Expenses (includes transportation) ($/BOE)	8.45	10.59	11.41
Light and Medium Crude Oil; Gas; NGLs			
Netback Received ($/BOE)[3]	62.05	53.34	50.22

Notes:

(1) Before deduction of royalties.
(2) NGL volumes are derived from natural gas production; as such all the related operating costs are attributed to the production of natural gas.
(3) Netbacks are calculated by subtracting royalties and operating costs from revenues.

The following table indicates Home Quarter's average daily production from its important fields for the nine months ended September 30, 2013:

	Light and Medium Crude Oil (bbl/d)	**Gas (Mcf/d)**	**NGLs (bbl/d)**	**BOE (BOE/d)**
Whiteside/Lucky Hills	1,569	2,907	30	2,083
Other properties	95	75	0	108
Total	1,664	2,982	30	2,191

For the nine months ended September 30, 2013, approximately 5% of Home Quarter's gross revenue was derived from natural gas production, 1% was derived from NGL production and the remaining 94% was derived from oil.

DESCRIPTION OF OUR CAPITAL STRUCTURE

Credit Facility

We have a $600 million 364-day revolving Credit Facility with a syndicate of Canadian banks consisting of a $400 million 364-day extendible revolving facility and a revolving operating facility and a $200 million term loan facility. The extendible revolving facility may be extended for a further 364-day revolving period upon our request. At the end of the revolving period, being May 29, 2014, the extendible revolving credit facility converts into a 366-day term loan. The Credit Facility bears interest at the bank's prime lending or bankers' acceptance rates plus applicable margins. The term loan facility matures on October 3, 2018 and has a fixed interest rate of 5.325%. The Credit Facility is secured by a $1 billion demand debenture in respect of all of our assets and a general assignment of book debts in respect of all of our accounts. The borrowing base is generally subject to review and redetermination by the lenders on an annual basis or in the event of a change in our borrowing base properties (due to a disposition of assets beyond certain defined limits or a change which results in a material adverse effect, as determined by the lenders). The next borrowing base review is to occur on or before May 29, 2014 and there can be no assurance that the current borrowing base level will be maintained. See "*Risk Factors – Credit Facility Arrangements*".

Pursuant to the terms of the Credit Facility, we are permitted to pay dividends provided that, if at both the date of declaration and payment of any such dividend, there is no borrowing base shortfall under the Credit Facility which has not been eliminated, no default has occurred which has not been cured or waived and no default or event of default could reasonably be expected to be caused by or result from such declaration or payment.

Share Capital

The following is a description of the rights, privileges, restrictions and conditions attaching to our share capital.

Common Shares

We are authorized to issue an unlimited number of Common Shares without nominal or par value. Subject to the provisions of the *Business Corporations Act* (Alberta), holders of our Common Shares are entitled to one vote per share at meetings of our Shareholders. Subject to the rights of the holders of preferred shares and any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by our Board of Directors and upon liquidation, dissolution or winding-up to receive, our remaining property.

Preferred Shares

We are authorized to issue an unlimited number of preferred shares without nominal or par value. Our Board of Directors may issue preferred shares at any time and from time to time in one or more series and shall fix the number of preferred shares in such series and determine the designation, rights, privileges, restrictions and conditions attaching the preferred shares. The preferred shares shall be entitled to priority over our Common Shares and over any other of our shares ranking junior to the preferred shares with respect to priority in the payment of dividends if, as and when declared by our Board of Directors and the receipt of our remaining property upon liquidation, dissolution or winding-up. There are currently no preferred shares issued or outstanding.

MARKET FOR OUR SECURITIES

Our Common Shares trade on the Toronto Stock Exchange under the trading symbol "WCP".

The following sets out the high and low trading prices and aggregate volume of trading for the periods noted below for the Common Shares:

Period	High	Low	Volume
2013			
January	9.62	8.70	32,345,608
February	9.58	8.55	22,547,914
March	9.95	8.71	70,187,939
April	10.51	9.33	33,424,455
May	11.17	10.06	22,830,762
June	11.01	10.02	29,460,456
July	11.41	10.48	25,662,704
August	11.48	11.00	27,051,986
September	12.27	11.06	22,545,683
October	12.94	11.59	28,206,571
November	12.87	11.35	36,217,836
December	12.84	12.28	13,999,365
2014			
January	12.73	11.60	47,831,943
February	12.05	11.28	40,932,865
March (1 - 20)	12.69	11.47	41,606,292

DIRECTORS AND OFFICERS

The names, municipalities of residence, any offices held with us, the period served as a director and principal occupations of our directors and officers are set out below.

Name and Municipality of Residence	Position with Whitecap	Director or Officer Since	Principal Occupation
Grant B. Fagerheim (2)(4)(5) Calgary, Alberta	Chairman, President, Chief Executive Officer and Director	June 2008	Our President and Chief Executive Officer since June 2008; President and Chief Executive Officer of Cadence Energy Inc. (formerly Kereco Energy Ltd.) a public oil and gas company from January 2005 to September 2008.
Gregory S. Fletcher (1)(2)(5) Calgary, Alberta	Director	September 2010	President of Sierra Energy Inc., a private oil and gas production company.
Glenn A. McNamara (2)(3) Calgary, Alberta	Director	September 2010	Chief Executive Officer and a director of Petromanas Energy Inc., a public oil and gas company. From August 2005 to August 2010, Mr. McNamara was the President of BG Canada (part of the BG Group PLC, a public gas company with its head office in the United Kingdom, trading on the London Stock Exchange). Prior thereto he was the President of ExxonMobil Canada Energy Corp. (a public oil and gas company).

Name and Municipality of Residence	Position with Whitecap	Director or Officer Since	Principal Occupation
Murray K. Mullen (3)(4) Calgary, Alberta	Director	August 2012	Chairman of the Board and Chief Executive Officer of Mullen Group Ltd. (a public transportation company), positions Mr. Mullen has held since 2001. Mr. Mullen joined the Mullen Group of companies in 1977 after graduating from the University of Calgary with a Bachelor of Arts (Economics) degree and has been a key architect of Mullen Group's overall business strategy and growth since it became public in 1993.
Stephen C. Nikiforuk (1)(5) Calgary, Alberta	Director	August 2009	President of MyOwnCFO Professional Corporation since October 2011; President of MyOwnCFO Inc. from July 2009 to June 2012 (both private companies); Corporate Business Manager of 1173373 Alberta Ltd. (a private company) from July 2009 to July 2011; Vice President, Finance and Chief Financial Officer of Cadence Energy Inc. (formerly Kereco Energy Ltd.) a public oil and gas company, from January 2005 to March 2008.
Kenneth S. Stickland (1)(3)(6) Calgary, Alberta	Director	June 2013	Independent businessman. Prior thereto, he was Chief Business Development Officer of TransAlta Corporation, a publicly traded electricity generating and marketing company from December 2012 to February 2014; September 2001 to December 2012, Chief Legal and Business Development Officer of TransAlta Corporation; May 2009 to September 2011 Chief Legal Officer of TransAlta Corporation. Has held various other legal positions with TransAlta Corporation since 2001.
Grant A. Zawalsky (4) Calgary Alberta	Director	August 2009	Managing Partner of Burnet, Duckworth & Palmer LLP, Barristers and Solicitors.
Joel Armstrong Calgary, Alberta	Vice President, Production and Operations	May 2010	Our Vice President, Production and Operations since May 2010; President of Maxwell Energy Inc. (a private oil and gas company) from September 2009 to May 2010; Vice President, Operations of Ridgeback Exploration Ltd. (a private oil and gas company) from May 2005 to July 2009.
Daniel Christensen Calgary, Alberta	Vice President, Exploration	September 2009	Our Vice President, Exploration since September 2009; Vice President, Exploration of Capex Exploration Ltd. (a private oil and gas company) from January 2005 to September 2008.
Darin Dunlop Calgary, Alberta	Vice President, Engineering	November 2009	Our Vice President, Engineering since November 2009; President of ReKon Energy Inc. (a private oil and gas company) from August 2009 to December 2009; Vice President, Engineering of Ridgeback Exploration Ltd. (a private oil and gas company) from March 2005 to August 2009.

Name and Municipality of Residence	Position with Whitecap	Director or Officer Since	Principal Occupation
Thanh Kang (5) Calgary, Alberta	Vice President, Finance and Chief Financial Officer	September 2009	Our Vice President, Finance and Chief Financial Officer since September 2009; Vice President, Finance and Chief Financial Officer of Churchill Energy Inc. (a public oil and gas company) from January 2005 to September 2008.
Gary Lebsack Calgary, Alberta	Vice President, Land	September 2009	Our Vice President, Land since September 2009; Vice President, Land of Glamis Resources Ltd. (a public oil and gas company) from January 2006 to July 2009.
David Mombourquette Calgary, Alberta	Vice President, Business Development	September 2009	Our Vice President, Business Development since September 2009; Vice President, Business Development of Cadence Energy Inc. (formerly Kereco Energy Ltd.) a public oil and gas company from January 2005 to September 2008.

Notes:
(1) Member of our audit committee.
(2) Member of our reserves committee.
(3) Member of our corporate governance and compensation committee.
(4) Member of our health, safety & environment committee.
(5) Member of our disclosure committee.
(6) Mr. Stickland was appointed to our Board of Directors on June 10, 2013.

The term of office of each of our directors expires at the next annual meeting of our Shareholders.

As at March 20, 2014 our directors and executive officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, 5.1 million Common Shares or approximately 2.6% of our issued and outstanding Common Shares.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

To our knowledge, 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 thirty 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.

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

To our knowledge, none of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, 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.

To our knowledge, 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

Our directors and officers may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See "*Risk Factors*".

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

The *Business Corporations Act* (Alberta) provides that in the event 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 interests arise, such conflicts will be resolved in accordance with the provisions of the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The full text of our Audit Committee charter is included in Appendix C of this Annual Information Form.

Composition of the Audit Committee

The members of our Audit Committee are Mr. Nikiforuk (Chair), Mr. Stickland and Mr. Fletcher, each of whom are independent and financially literate. We have adopted the definition of "independence" as set out in Section 1.4 of National Instrument 52-110 – *Audit Committees*. The relevant education and experience of each Audit Committee member is outlined below:

Stephen C. Nikiforuk: *MyOwnCFO Professional Corporation*

Mr. Nikiforuk has been the President of MyOwnCFO Professional Corporation since October 2011 and was the President of MyOwnCFO Inc. from July 2009 to June 2012, both private companies. Before then, Mr. Nikiforuk was the Corporate Business Manager of 1173373 Alberta Ltd. (a private company) from July 2009 to July 2011 and the Vice President, Finance and Chief Financial Officer of Cadence Energy Inc. (formerly Kereco Energy Ltd.) a public oil and gas company, from January 2005 to March 2008. Mr. Nikiforuk is an active Chartered Accountant and in 2013 completed the Directors Education Program developed by the Institute of Corporate Directors and holds their ICD.D designation. Mr. Nikiforuk also serves as a director on the boards of two private energy and energy related companies and also is on the board and acting Treasurer of a not for profit society. Mr. Nikiforuk holds a B.B.A. with an accounting major from Saint Francis Xavier University.

***Kenneth Stickland**: Independent Businessman*

Mr. Stickland is an independent businessman. Prior thereto, he was the Chief Business Development Officer of TransAlta Corporation a publicly listed, electricity generating and marketing company. Prior thereto, Mr. Stickland was a partner with a Calgary based law firm. Mr. Stickland has been the director of various associations and not-for-profit organizations. He has also been the director of several publicly listed companies. In these roles, Mr. Stickland has acquired significant experience and exposure to accounting and financial reporting issues.

***Gregory S. Fletcher**: Sierra Energy Inc.*

Mr. Fletcher is an independent businessman involved in the oil and natural gas industry in western Canada. He has considerable business experience in the junior sector of the oil and natural gas industry and is currently President of Sierra Energy Inc., a private oil and natural gas company that he founded in 1997. Mr. Fletcher is also a director of Peyto Exploration & Development Corp., a public oil and natural gas company, a director of Calfrac Well Services Ltd., a public oilfield service company and a director of Total Energy Services Inc., a public oilfield service company. In these roles, Mr. Fletcher has acquired significant experience and exposure to accounting and financial reporting issues. During 2009, Mr. Fletcher completed the Director Education Program developed by the Institute of Corporate Directors and the Rotman School of Management in conjunction with the Haskayne School of Business. Mr. Fletcher holds a BSc. in geology from the University of Calgary.

Pre-Approval of Policies and Procedures

Our Audit Committee has adopted a policy to review and pre-approve any non-audit services to be provided to us by our external auditors and will consider the impact on the independence of such auditors. The Audit Committee delegated to the Audit Chair the authority to pre-approve non-audit services, provided that the Chair reports to the Audit Committee at the next scheduled meeting such pre-approval and the Chair complies with such other procedures as may be established by our Audit Committee from time to time.

External Auditor Service Fees

Audit Fees

PricewaterhouseCoopers LLP are our auditors. PricewaterhouseCoopers LLP have been our auditors since October 2009. Fees we incurred with PricewaterhouseCoopers LLP for audit and non-audit services in the last two fiscal years are outlined in the following table.

Nature of Services	Fees Paid to Auditor in Year Ended December 31, 2013 ($)	Fees Paid to Auditor in Year Ended December 31, 2012 ($)
Audit Fees (1)	190,000	143,000
Audit-Related Fees (2)	-	-
Tax Fees (3)	64,700	83,000
All Other Fees (4)	192,000	180,700
Total	446,700	406,700

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of our financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) "Audit-Related Fees" for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported as audit fees. The services provided in this

category include due diligence assistance, accounting consultations on proposed transactions, and consultation on International Financial Reporting Standards conversion.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice.

(4) "All Other Fees" include all other non-audit services.

Reliance on Exemptions

At no time since the commencement of our most recently completed financial year have we relied on any of the exemptions contained in National Instrument 52-110 – *Audit Committees* with respect to independence or composition of our Audit Committee.

Audit Committee Oversight

At no time since commencement to the most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by our Board of Directors.

DIVIDEND POLICY

Dividends and Dividend Policy

On November 20, 2012 our Board of Directors adopted a dividend policy of paying monthly dividends at a rate of $0.05. On June 27, 2013, our Board of Directors approved a 5% increase to our monthly dividend to $0.0525 per Common Share starting with the October 2013 dividend payable in November 2013. On November 16, 2013, our Board of Directors approved an 8% increase to our monthly dividend to $0.0567 per Common Share starting with the January 2014 dividend payable in February 2014. Further, provided the asset acquisition closes, our Board of Directors approved a 10% increase to our dividend to $0.0625 per common share starting with the May 2014 dividend payable in June 2014. See "*General Development of our Business – Developments in 2013*" and "*General Development of our Business – Recent Developments.*"

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

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

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

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

Cash dividends are not guaranteed. Our historical cash dividends may not be reflective of future cash dividends, which will be subject to review by our Board of Directors taking into account our prevailing financial circumstances at the relevant time. Although we intend to make dividends of our available cash to Shareholders, these cash dividends may be reduced or suspended. The actual amount distributed will depend on numerous factors and conditions existing from time to time, including fluctuations in commodity prices,

production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends applicable law and other factors beyond our control. See "*Risk Factors – Dividends*".

The following monthly cash dividends on Common Shares were declared by us for the periods indicated:

For the Month Ended	Dividends per Common Share	Payment Date
March 31, 2014	$0.0567	April 15, 2014
February 28, 2014	$0.0567	March 17, 2014
January 31, 2014	$0.0567	February 17, 2014
December 31, 2013	$0.0525	January 15, 2014
November 30, 2013	$0.0525	December 16, 2013
October 31, 2013	$0.0525	November 15, 2013
September 30, 2013	$0.05	October 15, 2013
August 31, 2013	$0.05	September 16, 2013
July 31, 2013	$0.05	August 15, 2013
June 30, 2013	$0.05	July 15, 2013
May 31, 2013	$0.05	June 17, 2013
April 30, 2013	$0.05	May 15, 2013
March 31, 2013	$0.05	April 15, 2013
February 28, 2013	$0.05	March 15, 2013
January 29, 2013	$0.05	February 15, 2013

Unless otherwise specified, all dividends paid or to be paid by us are designated as "eligible dividends" under the *Income Tax Act* (Canada).

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 with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta and Saskatchewan, 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 is 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 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. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. he specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, 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. 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 National Energy Board of Canada. The National Energy Board of Canada is currently undergoing a consultation process to update the current regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* which received Royal Assent on June 29, 2012. In this transitory period, the National Energy Board of Canada has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the National Energy Board of Canada 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 National Energy Board of Canada 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 National Energy Board of Canada 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 National Energy Board of Canada.

The North American Free Trade Agreement

The North American Free Trade Agreement 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. The North American Free Trade Agreement 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. The North American Free Trade Agreement contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that 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 carved out of the working interest owner's interest, from time to time, 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. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%

Oil sands projects are also subject to 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 at 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, concurrent 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 new royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program 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 Innovative Energy Technologies Program provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, 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 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, 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 classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery scheme. 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. Royalties on natural gas liquids are levied at a flat rate of 20% of the sales volume.

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. It is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, 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. The production tax rate for freehold natural gas liquids is a flat rate of 12.25%.

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

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to 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 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs. Effective on April 1, 2014, the Deep Well Royalty Credit Program will have two tiers—"tier one" and "tier two". The existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program will apply to shallower horizontal wells with a true vertical depth less than 1,900 metres if spud after March 31, 2014;

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;

- *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;

- *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 a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m^3 for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000m^3;

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17m^3 per metre of depth for exploratory wildcat wells and less than 11m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000m^3. Effective on April 1, 2014, the Ultra-Marginal Royalty Reduction Program will no longer apply to horizontal wells due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; 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 that provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 3% minimum royalty on affected wells with deep well/deep re-entry credits. The 3% minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month.

Saskatchewan

In Saskatchewan, the amount payable as a Crown royalty or a 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 divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil being "fourth tier oil", "third tier oil", "new oil" and "old oil" depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and 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 as heavy oil 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, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" applicable to that classification of oil. Currently the "Production Tax Factor" is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for "old oil", "new oil" and "third tier oil", and 250 m^3 per month for "fourth tier 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 a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government, the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. 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 at least 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* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, 2012 which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3/month 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 $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule 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 current regulatory scheme provides for **c**ertain differences with respect to the administration of "fourth tier gas" which is associated 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 (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) 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) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) 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 (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) 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 total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of enhanced oil recovery projects during and subsequent to the payout of the enhanced oil recovery operations;

- *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% of enhanced oil recovery operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from enhanced oil recovery projects; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

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

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

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.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, 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 sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. 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 and the imposition of material fines and penalties.

Federal

Pursuant to the *Jobs, Growth and Long-term Prosperity Act,* the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the *Jobs, Growth and Long-term Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act*. On November 30, 2013, the Alberta Energy Regulator assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the Alberta Energy Regulator is expected to assume the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The Alberta Energy Regulator's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework. The Alberta Land Use Framework 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 seven 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.

Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* provides the legislative authority for the Government of Alberta to implement the policies contained in the Alberta Land Use Framework. Regional plans established under the *Alberta Land Stewardship Act* are 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 *Alberta Land Stewardship Act* 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 *Alberta Land Stewardship Act* also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, registrations, 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 *Alberta Land Stewardship Act* 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 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan which came into force on September 1, 2012. The Lower Athabasca Regional Plan is the first of seven regional plans developed under the Alberta Land Use Framework. Lower Athabasca Regional Plan covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82% of the province's oilsands resources and much of the Cold Lake oilsands area.

The Lower Athabasca Regional Plan establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oilsands companies' tenure has been (or will be) cancelled in conservation areas and no new oilsands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

The next regional plan to take effect is the South Saskatchewan Regional Plan, which covers approximately 83,764 square kilometres and includes 45% of the provincial population. The South Saskatchewan Regional Plan was released in draft form in 2013 and is expected to come into force on April 1, 2014.

With the implementation of the new Alberta regulatory structure under the Alberta Energy Regulator, Alberta Environment and Sustainable Resource Development will remain responsible for development and implementation of regional plans. However, the Alberta Energy Regulator will take on some responsibility for implementing regional plans in respect of energy related activities.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* impacts conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities in the province. Under the *Oil and Gas Activities Act*, the British Columbia Oil and Gas Commission has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The *Oil and Gas Activities Act* requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act* requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Saskatchewan

In May 2011, Saskatchewan passed changes to *The Oil and Gas Conservation Act*, the act governing the regulation of resource development operations in the province. Although the associated bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* and *The Petroleum Registry and Electronic Documents Regulations* ("**Registry Regulations**"). The aim of the amendments to *The Oil and Gas Conservation Act*, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the *Petroleum Registry and Electronic Documents Regulations* and the *Oil and Gas Conservation Regulations, 2012*, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects, including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

In Alberta, the Alberta Energy Regulator implements the Licensee Liability Rating Program. The Licensee Liability Rating Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The *Oil and Gas Conservation Act* establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the Licensee Liability Rating Program if a licensee or working interest participant becomes defunct. The Orphan Fund is funded by licensees in the Licensee Liability Rating Program through a levy administered by the Alberta Energy Regulator. The Licensee Liability Rating Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licences and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The Licensee Liability Rating Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the Alberta Energy Regulator with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the Alberta Energy Regulator.

Effective May 1, 2013, the Alberta Energy Regulator implemented important changes to the Licensee Liability Rating Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and

- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

These changes will be implemented over a three-year period. The first phase was implemented in May of 2013, the second phase will be implemented in May of 2014 and the final phase will be implemented in May 2015. The changes to the Licensee Liability Rating Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

British Columbia

In British Columbia, the Commission implements the Liability Management Rating ("**LMR**") Program, designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the LMR Program, the Commission determines the required security deposits for permit holders under the *Oil and Gas Activities Act*. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the *Oil and Gas Activities Act*.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program. The Licensee Liability Rating Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under *The Oil and Gas Conservation Act*. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the Licensee Liability Rating Program when a licensee or working interest participant is defunct or missing. The Licensee Liability Rating Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

Climate Change Regulation

Federal

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* and a participant to the Copenhagen Accord (a non-binding agreement created by the *United Nations Framework Convention on Climate Change* which represents a broad political consensus and reinforces commitments to reducing greenhouse gas emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of greenhouse gas emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

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 greenhouse gas 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, for application to regulated sectors on a facility-specific, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing greenhouse gas emissions and is working on regulations for other sectors. 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 greenhouse gas emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce greenhouse gas emissions.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing greenhouse gas emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

As part of its efforts to reduce greenhouse gas emissions, Alberta introduced legislation to address greenhouse gas emissions: the *Climate Change and Emissions Management Act* enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The *Climate Change and Emissions Management Act* is based on an emissions intensity approach and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the *Specified Gas Emitters Regulation*, which imposes greenhouse gas limits, and the *Specified Gas Reporting Regulation*, which imposes greenhouse gas emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to compliance with the *Climate Change and Emissions Management Act*. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their greenhouse gas emissions.

The *Specified Gas Emitters Regulation*, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of greenhouse gases in 2003 or any subsequent year, and requires reductions in greenhouse gas emissions intensity (e.g. the quantity of greenhouse gas emissions per unit of production) from emissions intensity baselines established in accordance with the *Specified Gas Emitters Regulation*. The *Specified Gas Emitters Regulation* distinguishes 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 by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 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 their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year and 10% of their baseline in the eighth year. The *Climate Change and Emissions Management Act* does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The *Climate Change and Emissions Management Act* provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also 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.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It 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 $30 per tonne of CO_2 equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. 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.

In the 2012 Budget, British Columbia announced that the government would undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review last year, British Columbia confirmed that it will keep its revenue-neutral carbon tax, the current carbon tax rates and tax base will be maintained and revenues will continue to be returned through tax reductions.

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. It sets a province-wide target of a 33% reduction in the 2007 level of greenhouse gas emissions by 2020 and an 80% reduction by 2050. 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 greenhouse gas emissions. The *Reporting Regulation*, implemented under the authority of the Cap and Trade Act, sets out the requirements for the reporting of the greenhouse gas emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Recent amendments to the Cap and Trade Act repealed past requirements on public-sector organizations, including Crown corporations, to be carbon neutral by 2010, and they are now only required to produce annual carbon reduction plans and reports. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under development.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* to regulate greenhouse gas emissions in the province. The *Management and Reduction of Greenhouse Gases Act* received Royal Assent on May 20, 2010 and will come into force on proclamation. The *Management and Reduction of Greenhouse Gases Act* establishes a framework for achieving the provincial target of a 20% reduction in greenhouse gas emissions from 2006 levels by 2020. The *Management and Reduction of Greenhouse Gases Act* and related regulations have yet to be proclaimed in force.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in our other public filings before making an investment decision. The risks set out below are not an exhaustive list, nor should be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, our existing reserves, and the production from them, will decline over time as we produce from such reserves. A future increase in our reserves will depend on both our ability to explore and develop our existing properties and on our ability to select and acquire suitable producing properties or prospects. There is no assurance that we will be able continue to find satisfactory properties to acquire or participate in. Moreover, our management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that we will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and 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, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, and spills or other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects.

As is standard industry practice, we are not fully insured against all risks, nor are all risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event we could incur significant costs.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader U.S. and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by the Organization of the Petroleum Exporting Countries and the ongoing global credit and liquidity concerns. This volatility may in the future affect our ability to obtain equity or debt financing on acceptable terms.

Prices, Markets and Marketing

Numerous factors beyond our control do, and will continue to affect the marketability and price of oil and natural gas acquired or discovered by us. Our ability to market our oil and natural gas may depend upon our ability to acquire space on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance of our reserves are to pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect us.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions, in the United States, Canada and Europe, the actions of the Organization of the Petroleum Exporting Countries, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. A material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change because of lower 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.

North American crude oil price differentials are expected to continue to be volatile throughout 2013 which will have an impact on crude oil prices for Canadian producers. Although opportunities to move oil by rail continue to grow and will provide new outlets for access to North American refineries otherwise not reachable via existing pipeline infrastructure, supply in excess of current pipeline and refining capacity is expected to continue to exist. Material structural changes are required to reduce these bottlenecks and the resulting steep price discounts. A variety of new pipeline expansion projects to provide increased access to eastern Canadian and Gulf Coast refineries, as well as new off-shore markets, have been announced and are in various stages of review and approval. There can be no assurance that such regulatory approvals will be secured on a timely basis or at all.

All these factors could result in a material decrease in our expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, the Organization of the Petroleum Exporting Countries actions, and sanctions imposed on certain oil producing nations by other countries and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. The price at which our Common Shares will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with ours. The integration of acquired businesses may require substantial management effort, time and resources diverting 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. In this regard, non-core assets may be periodically disposed of so that we can focus our 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, may realize less than their carrying value on our financial statements.

Operational Dependence

Other companies operate some of the assets in which we have an interest. We have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others depends upon a number of factors that may be outside of our control, including, but not limited to, 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.

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project delays may delay 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 be unable to market the oil and natural gas that we produce effectively.

Gathering and Processing Facilities and Pipeline Systems

We deliver our products through gathering, processing and pipeline systems some of which we do not own. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of 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 its production or in a reduction of the price offered for our production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In the recent year, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. 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, results of operations and cash flows.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

A portion of our production may, from time to time, be processed through facilities owned by third parties and over which we do not have control. 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 discontinuation or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale.

Competition

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

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before us. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be materially adversely affected. If we are unable to utilize the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil and other liquid hydrocarbons. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See: "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, we require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt a new or modify the royalty regime which may have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our operations, less economic.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. Specifically, hydraulic fracturing is used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, 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.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we are in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Climate Change

Our exploration and production facilities and other operations and activities emit greenhouse gases and which may require us to comply with greenhouse gas emissions legislation in Alberta or that may be enacted in other provinces. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* and as a participant to the Copenhagen Agreement (a non-binding agreement created by the *United Nations Framework Convention on Climate Change*), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. These greenhouse gas emission reduction targets are not binding, however. Although it is not the case today, some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage greenhouse gas emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. 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 the impact on the Corporation and its operations and financial condition.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/U.S. dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Future Canadian/United States exchange rates could accordingly affect the future value of our reserves as determined by independent evaluators.

To the extent that we engage in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which we may contract.

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a reduced amount available to fund our exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of our Common Shares.

Substantial Capital Requirements

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets
- our credit rating (if applicable);
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and our securities in particular.

Further, if our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to us. Our inability to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Additional Funding Requirements

Our cash flow from our reserves may not be sufficient to fund our ongoing activities at all times and from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, our access to additional financing may be affected.

Because of the global economic volatility, we may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable, or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of our petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties.

Credit Facility Arrangements

The amount authorized under our Credit Facility is dependent on the borrowing base determined by our lenders. We are required to comply with covenants under our Credit Facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in the default under the Credit Facility, which could result in us being required to repay amounts owing thereunder. Even if we are able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to us. If we are unable to repay amounts owing under our Credit Facility, our lenders could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, our Credit Facility may impose operating and financial restrictions on us that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

Our lenders use our reserves, commodity prices, applicable discount rate and other factors, to periodically determine our borrowing base. A material decline in commodity prices could reduce our borrowing base, reducing the funds available to us under our Credit Facility which could result in the requirement to repay a portion, or all, of our bank indebtedness.

Issuance of Debt

From time to time, we may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither our articles nor our by-laws limit the amount of indebtedness that we may incur. 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.

Hedging

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect us from commodity price declines, we may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time we may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, we will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim. Our actual interest in properties may, therefore, vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties we control that, if successful or made into law, could impair our activities on them and result in a reduction of the revenue received by us.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this annual information form are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates thereof and such variations could be material.

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

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from our oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and thus does not reflect changes in our reserves since that date.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although we maintain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, 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. The payment of any uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continue to affect the marketability and price of oil and natural gas acquired or discovered by us. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of our net production revenue.

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 may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have insurance to protect against the risk from terrorism.

Dilution

We may make future acquisitions or enter into financings or other transactions involving the issuance of our securities which may be dilutive.

Management of Growth

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 may have a material adverse effect on our business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

Our properties are held in the form of licences and leases and working interests in licences and leases. If we or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of our licences or leases or the working interests relating to a licence or lease may have a material adverse effect on our business, financial condition, results of operations and prospects.

Dividends

The amount of future cash dividends paid by us, 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 our control, our dividend policy may vary from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

The market value of our Common Shares may deteriorate if dividends are reduced or suspended. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of dividends paid by us and potential legislative and regulatory changes. Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and any decision by us to finance capital expenditures using funds from operations.

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 available for dividends may be reduced.

Litigation

In the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. We are not aware that any claims have been made in respect of our properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on our business, financial condition, results of operations and prospects.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, we may disclose confidential information relating to our business, operations or affairs. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

We file all required income tax returns and believe that we are in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of us, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects us. Furthermore, tax authorities having jurisdiction over us may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

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 our goods and services as the demand for natural gas rises during cold winter months and hot summer months.

Third Party Credit Risk

We may be exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In the event such entities 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.

Conflicts of Interest

Certain of our directors or officers may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the *Business Corporations Act* (Alberta) which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with us to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the *Business Corporations Act* (Alberta). See "*Directors and Officers – Conflicts of Interest*".

Reliance on Key Personnel

Our success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have any key person insurance in effect. 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.

Expansion into New Activities

Our operations and the expertise of our management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future we may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Forward-Looking Statements*" of this Annual Information Form.

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 our 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 security regulatory authority during the 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 before a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

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 Credit Facility, which is available on our SEDAR profile at www.sedar.com.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of our directors and senior officers, or any holder of our Common Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10% of our outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction completed within the last three years or in any proposed transaction during the current financial year which have materially affected or are reasonably expected to materially affect us, other than pursuant to the acquisition of Home Quarter where Mr. Grant

Zawalsky, one of our directors was also a director and shareholder of Home Quarter. Mr. Zawalsky did not participate in the meetings to approve the acquisition.

AUDITORS

PricewaterhouseCoopers LLP, Chartered Accountants, Suite 3100, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 5L3, is our auditor.

TRANSFER AGENT AND REGISTRAR

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

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, Sproule, independent engineering evaluator of Home Quarter, PricewaterhouseCoopers LLP, our independent auditors and KPMG LLP, the independent auditors of Home Quarter.

We used PricewaterhouseCoopers LLP for external audit and tax advisory services for the fiscal year ended December 31, 2013. PricewaterhouseCoopers LLP has advised us that they are independent with respect to us within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

As of January 23, 2014 and during the period covered by the financial statements of Home Quarter on which KPMG LLP reported, KPMG LLP were auditors of Home Quarter and have confirmed that they were independent with respect to Home Quarter within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

None of the designated professionals of McDaniel have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

Reserve estimates by Sproule in respect of Home Quarter are included in this Annual Information Form and incorporated by reference herein. None of the designated professionals of Sproule had any registered or beneficial interests, direct or indirect, in any securities or other property of Home Quarter either at the time they prepared the statement, report or valuation prepared by it.

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 associates or affiliates, except for Grant A. Zawalsky, one of our directors, is a partner at Burnet, Duckworth & Palmer LLP, which law firm renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on our SEDAR profile at www.sedar.com and on our website at www.wcap.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 will be contained in our proxy materials relating to our annual and special shareholders meeting to be held on May 1, 2014. Additional financial information is contained in our financial statements for the year ended December 31, 2013 and the related management's discussion and analysis.

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

Whitecap Resources Inc.
Suite 500, 222 – 3rd Avenue S.W.
Calgary, Alberta, T2P 0B4
Tel: (403) 266-0767
Fax: (403) 266-6975

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE FORM 51-101F3

Management of Whitecap Resources Inc. ("**Whitecap**") is responsible for the preparation and disclosure of information with respect to Whitecap's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

The Reserves Committee of the Board of Directors of Whitecap has:

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

(a) the content and filing with securities regulatory authorities of Form 51-101F2 containing reserves data and other oil and gas information;

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

(c) the content and filing of this report.

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

(signed) "*Grant B. Fagerheim*"
Grant B. Fagerheim
Chairman, President and Chief Executive Officer

(signed) "*Glenn A. McNamara*"
Glenn A. McNamara
Director, Chairman of the Reserves Committee and Member of the Compensation and Corporate Governance Committee

(signed) "*Darin Dunlop*"
Darin Dunlop
Vice President Engineering

(signed) "*Gregory S. Fletcher*"
Gregory S, Fletcher
Director and Member of the Audit Committee and the Reserves Committee

March 18, 2014

APPENDIX B

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

To the board of directors of Whitecap Resources Inc. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – $000s)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	Corporate Summary February 26, 2014	Canada	-	2,366,693.40	-	2,366,693.40

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

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

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

   Executed as to our report referred to above:

   McDaniel & Associates Consultants Ltd., Calgary, Alberta, Canada, February 26, 2014.

"ORIGINALLY SIGNED BY"

P.A. Welch, P. Eng.
President & Managing Director

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 of Whitecap Resources Inc. ("**Whitecap**") 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. 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 Whitecap and related matters;

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

3. To enhance the external auditor's independence;

4. To review 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 Whitecap, none of whom are members of management of Whitecap and all of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "independent" (as such term is used in National Instrument 52-110 - Audit Committees ("**NI 52-110**"). Provided that in the event that the common shares of Whitecap trade on the facilities of the TSX Venture Exchange, the Committee shall be comprised of at least three (3) directors of Whitecap, the majority of whom shall be "independent" (as such term is used in NI 52-110) in reliance of the exemptions afforded to venture issuers under NI 52-110.

2. The Board of Directors shall have the power to appoint the Committee Chairman, who shall be an unrelated director.

3. All of the members of the Committee shall be "financially literate". The Board of Directors of Whitecap has adopted the definition for "financial literacy" used in NI 52-110.

Meetings

1. 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.

2. 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.

3. 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 and shall be made available to the board. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

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

5. The Committee shall meet with the external auditor at least quarterly (including without management present) and at such other times as the external auditor and the audit Committee consider appropriate.

6. The auditor of Whitecap is entitled to receive notice of every meeting of the Committee and be heard thereat.

7. Meetings may be held by way of telephone conference call.

8. A written resolution signed by all Committee members entitled to vote on that resolution at a meeting of the Committee is as valid as one passed at a Committee meeting.

Mandate and Responsibilities of Committee

1. 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.

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

   - identifying, monitoring and mitigating business risks; and

   - ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review the annual and interim financial statements of Whitecap and the notes thereto 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 and reserves with respect to environmental matters;

   - 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.

4. The Committee is to review the financial statements, prospectuses, management discussion and analysis ("**MD&A**"), annual information forms ("**AIF**"), annual reports 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 Whitecap's disclosure of all other financial information and shall periodically assess the accuracy of those procedures. The Committee shall also review Whitecap's policies and procedures for making and updating disclosures on Whitecap's website and shall periodically assess the adequacy and accuracy of such policies and procedures.

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

   - ensure the auditor's ultimate accountability to the board of directors and the Committee as representatives of the shareholders and as such representatives, to evaluate the performance of the auditor;
   - 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;
   - 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;
   - ensure that the auditor submits on a periodic basis to the Committee, a formal written statement delineating all relationships between the auditor and Whitecap, consistent with Canadian and other applicable auditor independence standards, and to review such statement and to actively engage in a dialogue with the auditor with respect to any undisclosed relationships or services that may impact on the objectivity and independence of the auditor, and to review the statement and dialogue with the board of directors and recommend to the board of directors appropriate action to ensure the independence of the auditor;
   - provide a line of communication between the auditors and the board of directors; and
   - meet with the auditors at least once per quarter without management present to allow a candid discussion regarding any concerns the auditors may have and to resolve any disagreements between the auditor and management regarding Whitecap's financial reporting.

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

7. The Committee must pre-approve all non-audit services to be provided to Whitecap 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.

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

9. The Committee shall establish a procedure for:

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

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

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

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

12. The Committee shall review all related party transactions.

13. The Committee shall review the status of taxation matters of Whitecap and its major subsidiaries.

14. The Committee shall review the short term investment strategies respecting the cash balance of Whitecap.

15. The Committee shall conduct or undertake such other duties as may be required from time to time by any applicable regulatory authorities, including the TSX.

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