ZARGON OIL & GAS LTD.

2016 ANNUAL INFORMATION FORM

March 15, 2017

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GLOSSARY OF SELECTED TERMS

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

Entities

Board of Directors means our board of directors.

Debenture Trustee means Computershare Trust Company of Canada.

Exchangeable Shareholders means holders of Exchangeable Shares.

Macquarie Capital means Macquarie Capital Markets Canada Ltd.

Newco means 1563101 Alberta Ltd.

Oakmont means Oakmont Energy Ltd.

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

Scotia means Scotia Waterous Inc.

Shareholders mean holders of Common Shares.

TSX means Toronto Stock Exchange.

Trust means Zargon Energy Trust.

Unitholders means holders of Trust Units.

Zargon, **we**, **us** or **our** means Zargon Oil & Gas Ltd. and its controlled entities on a consolidated basis, and where the context requires, also means our predecessor issuer, the Trust and its controlled entities on a consolidated basis prior to the completion of the Arrangement.

ZEC means 1563101 Alberta Ltd.

ZEI means Zargon ExchangeCo Inc.

ZEL means Zargon Energy Ltd.

ZUSH means Zargon U.S. Holdings Ltd.

Independent Engineering

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook.

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

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

McDaniel Report means the report prepared by McDaniel dated February 23, 2017 evaluating the crude oil, natural gas and natural gas liquids reserves attributable to our oil and natural gas assets at December 31, 2016.

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

Securities and Other Terms

2016 Dispositions means the disposition of all of our Southeast Saskatchewan assets and our assets located in Killam, Alberta for total cash consideration of $92.04 million (after adjustments) which were completed in the third quarter of 2016

Arrangement means the arrangement among the Trust, Old Zargon, Newco, ZEI, Oakmont, ZEL, Zargon Acquisition Corp., Zargon Oil & Gas Partnership, the holders of Trust Units and the holders of Exchangeable Shares pursuant to Section 193 of the *Business Corporations Act* (Alberta) which commenced on December 31, 2010 and was completed on January 1, 2011.

Credit Agreement means the credit agreement dated as of January 1, 2011 as amended, which was repaid and terminated in 2016.

Common Shares means our issued and outstanding common shares.

Convertible Debentures means the $57.5 million aggregate principal amount of our 8.00% convertible unsecured subordinated debentures due December 31, 2019 which are currently convertible at the option of the holder, at any time, into fully paid Common Shares at a conversion price of $1.25 per Common Share and which may also be redeemed by us on maturity with cash or through the issuance of Common Shares priced at 95 percent of the current market price of the Common Shares on the maturity date.

Debenture Indenture means the indenture, as amended, between us and the Debenture Trustee governing the terms of the Convertible Debentures.

Exchangeable Shares means exchangeable shares of Old Zargon.

SEC means the United States Securities and Exchange Commission.

Shareholders mean holders of Common Shares.

Trust Unit means trust units of the Trust.

ABBREVIATIONS

Oil and Natural Gas Liquids		**Natural Gas**	
Bbl	barrel	gj	gigajoule
bbl/d	barrels per day	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	bcf	billion cubic feet
NGLs	natural gas liquids	Mcf/d	thousand cubic feet per day
		MMcf/d	million cubic feet per day
		MMbtu	million British Thermal Units

Other	
ASP	means alkaline surfactant polymer
BOE or boe	means barrel of oil equivalent
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent
Mmboe	million barrels of oil equivalent
Psi	pounds per square inch
WTI	West Texas Intermediate
^{o}API	the measure of the density or gravity of liquid petroleum products derived from a specific gravity
$000s	thousands 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	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	Bbls	6.289
feet	Metres	0.305
metres	Feet	3.281
miles	Kilometres	1.609
kilometres	Miles	0.621
acres	Hectares	0.405
hectares	Acres	2.471
gigajoules	MMbtu	0.948
MMbtu	Gigajoules	1.0551

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

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

NOTICE TO READER

Special Note Regarding Forward-Looking Statements

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "budget", "plan", "continue", "estimate", "expect", "forecast", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions (including the negative thereof). In addition, there are forward-looking statements in this Annual Information Form under the headings: "*General Development of Our Business*" relating to the goals of our strategic review process and our capital expenditure plans and sources of funding; "*Description of Our Business*" relating to our business plan, focus and strategy, our capital expenditure plans and sources of funding, our hedging strategy and the benefits to be obtained therefrom and our acquisition and disposition plans; "*Description of Our Business – Disclosure of Reserves Data and Other Oil and Natural Gas Information*" as to our reserves, future net revenues from our reserves, anticipated after-tax value of such revenues, pricing and inflation and exchange rates, future development costs and the sources of funding of our future development costs, our reclamation and abandonment obligations and the sources of funding such obligations, and the development of our proved undeveloped reserves and probable undeveloped reserves; "*Description of Our Business – Other Oil and Gas Information*" as to our future development activities and the results therefrom, drilling inventory, land expiries, hedging policies, tax horizon, production estimates, capital expenditures, and the allocation thereof, our development plans, and anticipated future production and oil recovery from our ASP project; "*Our Capital Structure*" with respect to our expectations regarding sources of financing and certain matters relating to our convertible debentures and the redemption of a portion thereof pursuant to the Put Right; and "*Dividends*" with respect to our dividend policy. This information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including such as those relating to results of operations and financial condition, general economic conditions, industry conditions, changes in regulatory and taxation regimes, volatility of commodity prices, escalation of operating and capital costs, regulatory approvals required in connection with our Little Bow ASP project, currency fluctuations, the availability of services, imprecision of reserve estimates, geological, technical, drilling and processing problems, environmental risks, weather, the lack of availability of qualified personnel or management, stock market volatility, the ability to access sufficient capital from internal and external sources and competition from other industry participants for, among other things, capital, services, acquisitions of reserves, undeveloped lands and skilled personnel. Such forward-looking information is provided for the purpose of providing information about management's current expectations and plans relating to the future to allow investors to have a greater understanding of our business. Readers are cautioned that reliance on such information may not be appropriate for other purposes, such as making investment decisions.

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

We believe the expectations reflected in these forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

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

- our business plan and strategy;
- the performance characteristics of our oil and natural gas properties;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under governmental regulatory regimes and tax laws.

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

- declines in oil and natural gas prices;
- variations in interest rates and foreign exchange rates;
- uncertainties relating to the global economy and access to capital, stock market volatility, market valuations and increased borrowing costs;
- refinancing risk for existing debt and debt service costs;
- access to external sources of capital, borrowings and equity sales;
- risks associated with our hedging activities;

- geological, technical, drilling and processing problems;
- third party credit risk;
- risks associated with the exploitation of our properties and our ability to acquire reserves;
- government regulation and control and changes in governmental legislation;
- changes in income tax laws, royalty rates and other incentive programs;
- uncertainties associated with estimating oil and natural gas reserves;
- risks associated with acquiring, developing and exploring for natural gas and other aspects of our operations;
- risks associated with the marketability of oil and natural gas;
- changes in climate change laws and other environmental regulations;
- risks associated with the exploitation of our properties and our ability to acquire reserves;
- the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth;
- competition in the oil and natural gas industry;
- depletion of our reserves;
- risks associated with large projects or expansion of our activities;
- risks associated with retention of key personnel;
- risks associated with securing and maintaining our properties;
- seasonality; and
- risks associated with the timing of payment of dividends.

In addition, statements relating to "reserves" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future.

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

Access to Documents

Any document referred to in this Annual Information Form and described as being filed on SEDAR at www.sedar.com (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at Suite 700, 333 – 5th Avenue S.W., Calgary, Alberta, T2P 3B6.

Drilling Locations

This Annual Information Form discloses drilling locations in four categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations; and (iv) an aggregate total of (i), (ii) and (iii). Of the 35 drilling locations referred to in this Annual Information Form, six are proved undeveloped locations, seven are probable undeveloped locations, and 22 are unbooked locations. Proved undeveloped locations and probable undeveloped locations are booked and derived from the McDaniel Report and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that we will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which we will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Oil and Gas Metrics

This Annual Information Form contains certain oil and gas metrics which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this document to provide readers with additional measures to evaluate our performance however, such measures are not reliable indicators of our future performance and future performance may not compare to our performance in previous periods and therefore such metrics should not be unduly relied upon.

ZARGON OIL & GAS LTD.

General

Pursuant to the January 1, 2011 Arrangement, we continued as "Zargon Oil & Gas Ltd." upon the amalgamation of Old Zargon, Newco, ZAC, ZEI and Oakmont. The Arrangement involved an internal reorganization of the Trust and certain of its subsidiaries through which the trust structure was replaced with a corporate structure and the Trust was dissolved. Pursuant to the Arrangement: (i) on December 31, 2010, the Trust Units were exchanged for common shares of Newco on a one-for-one basis, the Exchangeable Shares were exchanged for common shares of Newco on the basis of 1.84716 common shares of Newco for each outstanding Exchangeable Share, and Newco acquired all of the assets and assumed all of the liabilities of the Trust; and (ii) on January 1, 2011, the Trust was dissolved and Old Zargon, Newco, ZAC, ZEI and Oakmont amalgamated. Following the Arrangement, we, together with our subsidiaries, owned, directly or indirectly, the same assets that were owned by the Trust and its subsidiaries immediately prior to the Arrangement. The Arrangement has been accounted for as a continuity of interests and, unless otherwise indicated, all information presented for the pre-Arrangement period in this Annual Information Form relates to the Trust.

On January 1, 2014, our wholly owned subsidiary, Ashton Oil & Gas Ltd., was amalgamated into us.

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

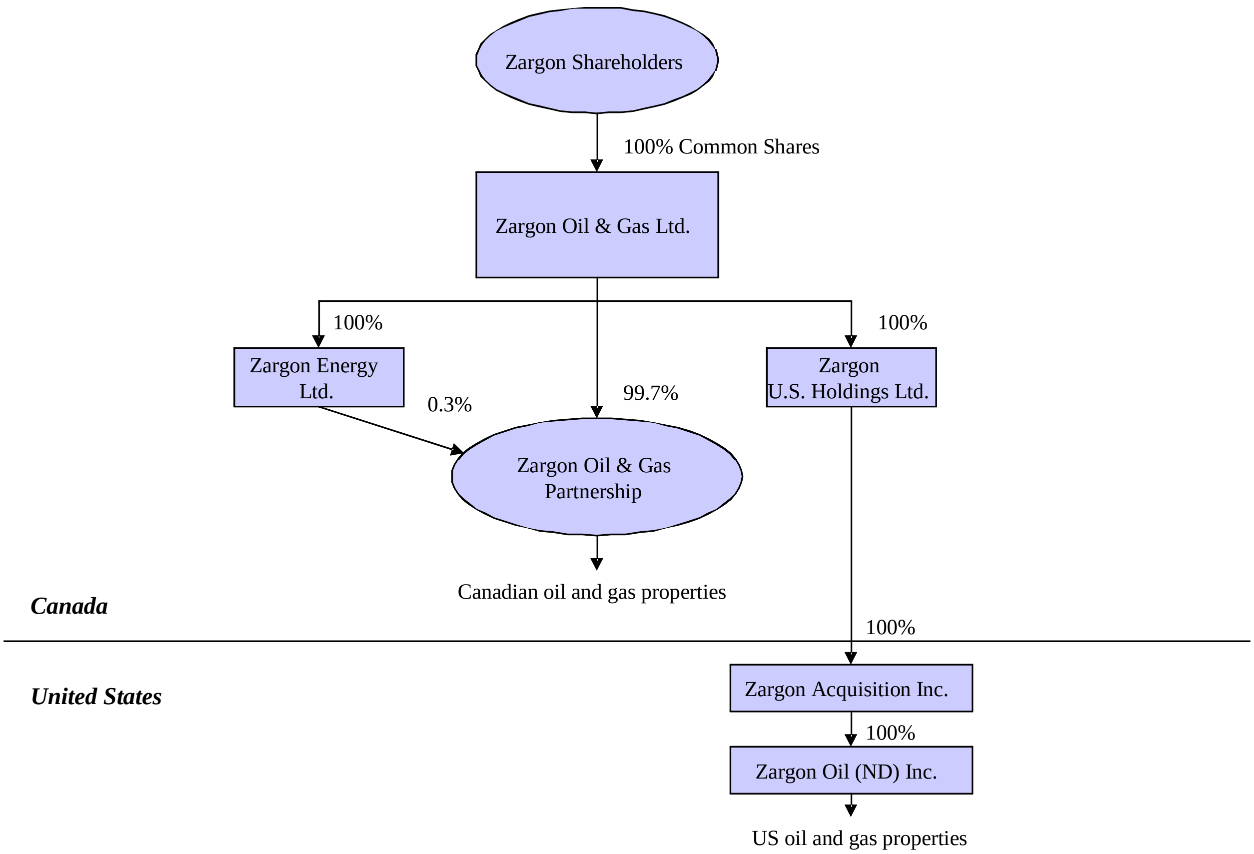
Inter-Corporate Relationships

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

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

Our Organization Structure

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



GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

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

Developments in 2014

In the first half of 2014, we completed six property sale transactions, which raised $4.7 million of net proceeds from the net disposition of 32 bbl/d of oil and 1.05 Mmcf/d of natural gas. In the third quarter of 2014, we completed several property sale transactions, which raised $6.6 million of net proceeds from the net disposition of 17 bbl/d of oil and 7.08 Mmcf/d of natural gas. These transactions included the sale of our Jarrow natural gas property in East Central Alberta on September 3, 2014, that had been producing a net 5.50 Mmcf/d interest.

On December 19, 2014, we completed the sale of our Hamilton Lake property for $22.5 million in cash (before adjustments) and 1.19 million common shares of Toro Oil & Gas Ltd., which included net production to us of approximately 170 bbl/d of oil and 1.40 Mmcf/d of natural gas. The cash proceeds from these dispositions were used to reduce our indebtedness under our Credit Agreement, which was amended due to the Hamilton Lake sale to reset the borrowing base at $130 million.

In the third quarter of 2014 we set our 2015 capital budget at $46 million, which allocated $21 million to ASP related expenditures and $25 million to conventional capital expenditures. Recognizing the challenging 2015 oil price environment, in December of 2014, we completed a reassessment of our 2015 capital budget and decreased our 2015 conventional capital budget from $25 million to $12 million and set our 2015 ASP budget at $20 million. We also announced our intention to reduce our monthly dividend to $0.03 per Common Share beginning with the January 2015 dividend, payable in February 2015.

Developments in 2015

On May 14, 2015, we promoted Jeffrey Post to the position of our Chief Financial Officer. Mr. Post joined us in 2009 and had served as our Corporate Controller since February 2014.

On June 18, 2015, we amended our Credit Agreement and reduced the borrowing base to $110 million, a reduction from the previous amount of $130 million.

In June of 2015, we lowered our monthly dividend to $0.01 per Common Share beginning with the July 2015 dividend, payable in August 2015.

On July 20, 2015, Ron Wigham was appointed to our Board of Directors. Mr. Wigham is currently President of Wigham Resources Limited and a director of Spur Resources Ltd., both private oil and gas companies and a director of Tourmaline Oil Corp., a TSX listed public oil and gas company. He retired in 2014 as Vice-Chairman of Peters and Company, a Calgary investment dealer specializing in oil and gas and oilfield services equities.

On August 13, 2015, our Board of Directors initiated a process to identify and consider strategic and financial alternatives available to us with the ultimate goal of maximizing shareholder value in a manner that would recognize our fundamental inherent value related to our long-life, low-decline conventional oil assets and the significant long term oil potential related to the Little Bow ASP project.

On November 10, 2015, following the semi-annual review of our syndicated credit facilities, the borrowing base of the Credit Agreement was reduced to $88 million from $110 million.

On November 11, 2015, we announced that as a result of volatile, uncertain and exceptionally low oil prices, we had decided to suspend our monthly dividend until further notice after the November 16, 2015 dividend payment.

During 2015 our capital expenditures totaled approximately $25 million (excluding $0.6 million relating to final statement of adjustments for prior year dispositions), 76% of which was allocated to our Little Bow ASP project with $12 million allocated to ASP chemical costs and $7 million to ASP exploitation costs. The remaining $6 million of capital expenditures were allocated to minor waterflood and facility modifications that continue to enable us to have a low base oil production decline of approximately 13 percent. During the year, we drilled 6.0 net wells yielding 6.0 net oil ASP wells. We did not drill any conventional oil exploitation wells in 2015.

Developments in 2016

On May 4, 2016, we announced that Scotia Waterous Inc. had initiated a broad corporate marketing process, on our behalf.

On June 21, 2016, we amended our Credit Agreement and reduced the borrowing base to $70 million, a reduction from the previous amount of $88 million and to provide that the facilities would continue to be revolving until September 22, 2016, with the provision for a nine month extension at the option of the lenders and upon our request.

On July 25, 2016, we entered into a definitive agreement for the sale of all of our Southeast Saskatchewan assets for cash consideration of $89.5 million, subject to normal closing adjustments, which included net production to us of approximately 1,211 boe/d of low decline production (approximately 95% oil and NGLs) and proved plus probable reserves (effective December 31, 2015) of 5.14Mboe. We completed the sale of our Southeast Saskatchewan assets on September 1, 2016. The proceeds from the disposition were used to eliminate our bank debt and the Credit Agreement was terminated.

On the same day, we announced that we had entered into a definitive agreement for the sale of all of our Killam, Alberta assets for $4.0 million, subject to normal closing adjustments, which included net production to us of approximately 133 boe/d of production (approximately 58 percent oil and NGLs) and proved plus probable reserves (effective December 31, 2015) of 0.67Mboe. This sale was completed in mid-September.

The realization of $92.04 million of cash proceeds from the 2016 Dispositions (after adjustments) was a partial outcome of our strategic alternatives process. The bank was fully repaid on October 25, 2016 and the credit facility was terminated. The remaining bank debt balance as at December 31, 2016 was nil. With the elimination of the Credit Agreement, the strategic alternatives process has been refocused to include, among other alternatives, a restructuring of our capital structure, the addition of capital to further develop the potential of our assets, the sale of us or a portion of our assets, a merger, a farm-in or joint venture, or such other options as may be determined by our Board of Directors to be in our best interests and our stakeholders. We have engaged Macquarie Capital as our exclusive financial advisor related to this component of our strategic alternatives process.

On October 17, 2016, we announced that Mr. Jeffrey Post had tendered his resignation as Chief Financial Officer effective November 14, 2016 to pursue other opportunities. At this time, we also completed a comprehensive corporate reorganization to align Zargon's staff with its smaller operational base. Pursuant to the reorganization, Brian Kergan, Vice President, Corporate Development; Rob Moriyama, Vice President, Enhanced Recovery; and Pete Janjua, Vice President, Williston Basin resigned, but agreed to provide consulting services to us when required.

On November 30, 2016, we announced the appointment of Mr. William T. (Bill) Cromb as our Interim Chief Financial Officer. At the same time, we announced that we had entered into hedges to fix the WTI price of oil on 650 bbl/d of oil production at an average of $66.98 in Canadian dollars for 2017.

On December 12, 2016, we announced that our Board of Directors had approved our 2017 capital budget of $7.8 million which was expected to maintain production at stable fourth quarter 2016 guidance levels and which would be fully funded out of 2017 funds flow.

Recent Developments

On January 12, 2017, we announced that we had entered into hedges to fix the WTI price of oil on 650 bbl/d of oil production at an average of $71.50 in Canadian dollars for the period February to December 2017 bringing the total volumes hedged from February to December 2017 to 1,300bbl/d at an average price of $69.24 Canadian.

On February 14, 2017, following an extraordinary meeting of the holders of our Convertible Debentures, we amended the terms of the Debenture Indenture and the Convertible Debentures to: (i) extend the maturity date of the Convertible Debentures from June 30, 2017 to December 31, 2019; (ii) increase the interest rate of the Convertible Debentures from 6.00% per annum to 8.00% per annum effective April 1, 2017; (iii) change the interest payment dates applicable to the Convertible Debentures under the Debenture Indenture from June 30, and December 31 to March 31, and September 30; (iv) reduce the conversion price in effect for each Common Share to be issued upon the conversion of the Convertible Debentures from $18.80 to $1.25; (v) amend the redemption provisions of the Convertible Debentures to provide holders with a right (the "**Put Right**") to require us to redeem up to $19 million aggregate principal amount of Convertible Debentures (or such other amount as may be determined by us) (the "**Maximum Redemption Amount**") at a cash price determined by a "Dutch auction" process; and (vi) amend the redemption provisions to provide that (other than in connection with the Put Right) the Convertible Debentures are not redeemable by us before January 1, 2019, and for the 12 months following January 1, 2019, the Convertible Debentures may only be redeemed by us if the Current Market Price (as defined in the Debenture Indenture) of the Common Shares exceeds 125% of the reduced conversion price.

Pursuant to the Put Right holders of Convertible Debentures may tender a minimum of $1,000 principal amount of their Convertible Debentures, and additional Convertible Debentures in integral amounts of $1,000, for redemption pursuant to auction tenders in which such tendering holders specify a redemption price, in increments of $10, of not less than $890 and not more than $1,000 per $1,000 principal amount Convertible Debenture. Unless otherwise terminated, extended or amended, the Put Right will expire at 5:00 p.m. (Eastern time) on March 31, 2017 (the "**Expiration Time**"). Promptly following the Expiration Time, we will redeem the Convertible Debentures tendered, starting with those tendered at the lowest redemption price, and continuing with those tendered at increasing incremental redemption prices, until we have redeemed not more than the Maximum Redemption Amount of tendered Convertible Debentures.

On February 27, 2017, the company entered into a hedge to fix the differential between WTI and WCS (Western Canadian Select) at $19.50 Canadian dollars for the period April to December 2017.

Significant Acquisitions

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

DESCRIPTION OF OUR BUSINESS

General

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

Our business plan is to deliver sustainable and profitable oil and natural gas property exploitation and production activities in the oil and natural gas industry. In recent years we have refocused our business on our long-life and low-decline conventional oil exploitation properties plus our Little Bow ASP tertiary oil project.

Capital Expenditures

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

We may acquire additional properties and related tangible equipment and fund such acquisitions from production revenues, the net proceeds of any issue of additional Common Shares or other securities or from the proceeds of disposition of properties, or from borrowings, farmouts or with working capital. We may sell any of our interests in properties. In connection with the sale of any interests in our properties, we will determine whether the net proceeds of the sale should be reinvested in additional properties or capital expenditures, used to repay debt or distributed to our Shareholders.

Potential Acquisitions

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

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. We compete with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Our competitors include resource companies, which may have greater financial resources, staff and facilities than ours. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery.

Cyclical and Seasonal Impact of Industry

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

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2017 by the renegotiation or termination of contracts or subcontracts. See "*Risk Factors – Risks Relating to Our Business and Operations*".

Bankruptcy and Similar Procedures

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

Material Restructuring Transactions

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

Human Resources

At December 31, 2016, we employed 19 full-time employees, including 13 office and six field employees.

Disclosure of Reserves Data and Other Oil and Natural Gas Information

This statement of reserves data and other oil and gas information set forth below is dated February 23, 2017. The effective date of the statement is December 31, 2016 and the preparation date of the statement is February 23, 2017. Readers should also refer to the Report of Management and Directors on Oil and Gas Disclosure attached hereto as Appendix A and the Report on Reserves Data by McDaniel attached hereto as Appendix B.

The reserves data set forth below is based upon an evaluation by McDaniel with an effective date of December 31, 2016 contained in the McDaniel Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The McDaniel Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. We engaged McDaniel to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

Our reserves are in Canada in the province of Alberta, and in the United States in North Dakota.

We determined the future net revenue and present value of future net revenue after income taxes by utilizing McDaniel's before income tax future net revenue and our estimate of income tax. Our estimate of cash income tax makes use of the following assumptions: corporate income tax at the current legislated rate; annual general and administrative expenses at the current rate; interest expense at the current rate; tax pool deductions utilizing our existing estimated $192 millions of tax pools and forecasted additions to our tax pools from capital expenditures as forecast by McDaniel and any such other additional deductions and adjustments as is and would be consistent with the manner in which we file and would file future tax returns. The after-tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different.

Future net revenue is a forecast of revenue, estimated using forecast prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs and abandonment and reclamation costs. Estimated values of future net revenues presented in the tables below do not represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of our crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. For more information as to the risks involved, see "*Risk Factors – Risks Relating to Our Business and Operations*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

CANADA

	LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved								
Developed Producing	1,222	1,050	3,366	3,164	4,753	4,357	52	39
Developed Non-Producing	35	35	375	355	1,620	1,458	28	20
Undeveloped	(1)	-	100	91	8	7	-	-
Total Proved	**1,256**	**1,085**	**3,841**	**3,610**	**6,381**	**5,822**	**80**	**59**
Probable	**604**	**521**	**2,795**	**2,588**	**3,985**	**3,571**	**43**	**35**
Total Proved Plus Probable	**1,860**	**1,606**	**6,636**	**6,198**	**10,366**	**9,393**	**123**	**94**

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	98,128	79,754	66,389	56,669	49,398
Developed Non-Producing	10,725	7,103	4,811	3,267	2,183
Undeveloped	2,178	1,585	1,147	825	590
Total Proved	**111,031**	**88,442**	**72,347**	**60,762**	**52,171**
Probable	**101,487**	**57,393**	**33,747**	**20,023**	**11,574**
Total Proved Plus Probable	**212,518**	**145,835**	**106,094**	**80,785**	**63,745**

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year) 0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	98,129	79,755	66,390	56,668	49,398
Developed Non-Producing	10,725	7,102	4,809	3,266	2,184
Undeveloped	2,177	1,585	1,148	827	589
Total Proved	**111,031**	**88,442**	**72,347**	**60,761**	**52,171**
Probable	**92,213**	**53,580**	**32,047**	**19,217**	**11,171**
Total Proved Plus Probable	**203,244**	**142,022**	**104,394**	**79,978**	**63,342**

BY PRODUCT TYPE
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	PRODUCTION GROUP	NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE (1) BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($/bbl or $/Mcf)
Proved	Light and Medium Crude Oil (2)	18,346	16.04
	Heavy Crude Oil (2)	52,812	14.63
	Conventional Natural Gas (3)	1,189	0.20
	Total	**72,347**	
Proved plus Probable	Light and Medium Crude Oil (2)	27,915	16.42
	Heavy Oil (2)	75,567	12.19
	Conventional Natural Gas (3)	2,612	0.28
	Total	**106,094**	

Notes:

(1) Unit values are based on net reserve volumes.
(2) Including solution gas and other by-products.
(3) Including by-products, but excluding solution gas and by-products from oil wells.

SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2016 FORECAST PRICES AND COSTS

UNITED STATES

RESERVES CATEGORY	LIGHT AND MEDIUM CRUDE OIL Gross (Mbbl)	LIGHT AND MEDIUM CRUDE OIL Net (Mbbl)	HEAVY CRUDE OIL Gross (Mbbl)	HEAVY CRUDE OIL Net (Mbbl)	CONVENTIONAL NATURAL GAS Gross (MMcf)	CONVENTIONAL NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
Proved								
Developed Producing	1,644	1,243	-	-	-	-	-	-
Developed Non-Producing	75	56	-	-	-	-	-	-
Undeveloped	255	194	-	-	-	-	-	-
Total Proved	**1,974**	**1,493**	-	-	-	-	-	-
Probable	**586**	**444**	-	-	-	-	-	-
Total Proved Plus Probable	**2,560**	**1,937**	-	-	-	-	-	-

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year) 0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	26,585	22,206	17,880	14,725	12,476
Developed Non-Producing	3,231	1,941	1,254	841	574
Undeveloped	4,906	2,971	1,723	905	354
Total Proved	**34,722**	**27,118**	**20,857**	**16,471**	**13,404**
Probable	**16,444**	**9,119**	**5,325**	**3,470**	**2,468**
Total Proved Plus Probable	**51,166**	**36,237**	**26,182**	**19,941**	**15,872**

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year) 0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	14,694	13,847	11,541	9,659	8,272
Developed Non-Producing	2,031	1,191	754	490	317
Undeveloped	2,984	1,584	664	57	(350)
Total Proved	**19,709**	**16,622**	**12,959**	**10,206**	**8,239**
Probable	**9,956**	**5,843**	**3,385**	**2,180**	**1,540**
Total Proved Plus Probable	**29,665**	**22,465**	**16,344**	**12,386**	**9,779**

BY PRODUCT TYPE
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

UNITED STATES

RESERVES CATEGORY	PRODUCTION GROUP	NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE [(1)] BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($/bbl or $/Mcf)
Proved	Light and Medium Crude Oil [(2)]	20,857	13.97
	Heavy Crude Oil [(2)]	-	
	Conventional Natural Gas [(3)]	-	
	Total	**20,857**	
Proved plus Probable	Light and Medium Crude Oil [(2)]	26,182	13.52
	Heavy Oil [(2)]	-	
	Conventional Natural Gas [(3)]	-	
	Total	**26,182**	

Notes:

(1) Unit values are based on net reserve volumes.
(2) Including solution gas and other by-products.
(3) Including by-products, but excluding solution gas and by-products from oil wells.

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

AGGREGATE

	LIGHT AND MEDIUM CRUDE OIL		HEAVY CRUDE OIL		CONVENTIONAL NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved								
Developed Producing	2,866	2,293	3,366	3,164	4,753	4,357	52	39
Developed Non-Producing	110	91	375	355	1,620	1,458	28	20
Undeveloped	254	194	100	91	8	7	-	-
Total Proved	**3,230**	**2,578**	**3,841**	**3,610**	**6,381**	**5,822**	**80**	**59**
Probable	**1,190**	**965**	**2,795**	**2,588**	**3,985**	**3,571**	**43**	**35**
Total Proved Plus Probable	**4,420**	**3,543**	**6,636**	**6,198**	**10,366**	**9,393**	**123**	**94**

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES DISCOUNTED AT (%/year) 0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	124,713	101,960	84,269	71,394	61,874
Developed Non-Producing	13,956	9,044	6,065	4,108	2,757
Undeveloped	7,084	4,556	2,870	1,731	944
Total Proved	**145,753**	**115,560**	**93,204**	**77,233**	**65,575**
Probable	**117,931**	**66,512**	**39,072**	**23,493**	**14,042**
Total Proved Plus Probable	**263,684**	**182,072**	**132,276**	**100,726**	**79,617**

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAX EXPENSES DISCOUNTED AT (%/year) 0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)
Proved					
Developed Producing	112,823	93,602	77,931	66,327	57,670
Developed Non-Producing	12,756	8,293	5,563	3,756	2,501
Undeveloped	5,161	3,169	1,812	884	239
Total Proved	**130,740**	**105,064**	**85,306**	**70,967**	**60,410**
Probable	**102,169**	**59,423**	**35,432**	**21,397**	**12,711**
Total Proved Plus Probable	**232,909**	**164,487**	**120,738**	**92,364**	**73,121**

BY PRODUCT TYPE
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

AGGREGATE

RESERVES CATEGORY	PRODUCTION GROUP	NET PRESENT VALUE OF FUTURE NET REVENUE BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($000s)	UNIT VALUE [1] BEFORE INCOME TAX EXPENSES (discounted at 10%/year) ($/bbl or $/Mcf)
Proved	Light and Medium Crude Oil [2]	39,203	14.87
	Heavy Crude Oil [2]	52,812	14.63
	Conventional Natural Gas [3]	1,189	0.20
	Total	**93,204**	
Proved plus Probable	Light and Medium Crude Oil [2]	54,097	14.87
	Heavy Oil [2]	75,567	12.19
	Conventional Natural Gas [3]	2,612	0.28
	Total	**132,276**	

Notes:

(1) Unit values are based on net reserve volumes.
(2) Including solution gas and other by-products.
(3) Including by-products, but excluding solution gas and by-products from oil wells.

TOTAL FUTURE NET REVENUE

(UNDISCOUNTED)
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

($000s) RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT AND RECLAMATION COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
Proved Reserves								
Canada	388,049	32,907	212,674	13,246	18,191	111,031	-	111,031
United States	158,811	38,678	71,859	5,690	7,862	34,722	15,013	19,709
Total	546,860	71,585	284,533	18,936	26,053	145,753	15,013	130,740
Proved Plus Probable Reserves								
Canada	674,042	58,366	322,683	58,588	21,887	212,518	9,274	203,244
United States	220,947	53,820	100,905	5,690	9,366	51,166	21,501	29,665
Total	894,989	112,186	423,588	64,278	31,253	263,684	30,775	232,909

Definitions and Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

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

   Reserve Categories

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

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

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

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

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

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

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

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

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

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

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

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

Levels of Certainty for Reported Reserves

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

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

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

Forecast Prices and Costs

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, as at December 31, 2016, inflation and exchange rates utilized in the McDaniel Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Bow River Hardisty API ($Cdn/bbl)	Alberta Heavy 12° API ($Cdn/bbl)	Cromer Medium 29.3° API ($Cdn/bbl)	Natural Gas AECO Price ($Cdn/ MMBTU)	Natural Gas Liquids FOB Field Gate ($Cdn/bbl) [(3)]	Inflation Rate[(1)] %/year	Exchange Rate[(2)] ($US/ $Cdn)
Forecast									
2017	55.00	69.80	54.40	46.50	62.80	3.40	40.30	-	0.750
2018	58.70	72.70	58.90	50.50	67.60	3.15	42.60	2.0	0.775
2019	62.40	75.70	62.70	54.00	70.20	3.30	44.90	2.0	0.800
2020	69.00	81.10	67.30	58.00	75.40	3.60	49.30	2.0	0.825
2021	75.80	86.60	71.90	61.90	80.50	3.90	53.80	2.0	0.850
2022	77.30	88.30	73.30	63.10	82.10	3.95	54.90	2.0	0.850
2023	78.80	90.00	74.70	64.40	83.71	4.10	55.90	2.0	0.850
2024	80.40	91.80	76.20	65.60	85.40	4.25	57.10	2.0	0.850
2025	82.00	83.70	77.80	67.00	87.10	4.30	58.30	2.0	0.850
2026	83.70	95.60	79.30	68.40	88.90	4.40	59.50	2.0	0.850
2027	85.30	97.40	80.80	69.60	90.60	4.50	60.60	2.0	0.850
2028	87.00	99.40	82.50	71.10	82.40	4.60	61.80	2.0	0.850
2029	88.80	101.40	84.20	72.50	94.30	4.65	63.10	2.0	0.850
2030	90.60	103.50	85.90	74.00	96.30	4.75	67.80	2.0	0.850
2031	92.40	105.50	87.60	75.40	98.10	4.85	65.70	2.0	0.850
Thereafter:	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	Escalate at 2.0%/year	2.0	0.850

Notes:

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.
(3) NGL mix calculated from McDaniel Report based on 45 percent propane, 35 percent butane and 20 percent natural gasoline of Edmonton propane, Edmonton butanes and Edmonton condensate and natural gasoline reference prices, respectively.

Weighted average historical prices realized by us (before the impact of financial risk management contracts) for the year ended December 31, 2016, were $1.95/Mcf for conventional natural gas, $41.82/bbl for light and medium crude oil, $22.85/bbl for natural gas liquids and $36.22/bbl for heavy crude oil.

Future Development Costs

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

CANADA

	Forecast Prices and Costs	
Year ($000s)	Proved Reserves	Proved Plus Probable Reserves
2017	3,056	3,527
2018	9,362	23,690
2019	688	21,168
2020	-	5,724
2021	-	3,287
Thereafter	140	1,192
Total Undiscounted	13,246	58,588
Total Discounted at 10%	11,553	47,455

UNITED STATES

	Forecast Prices and Costs	
Year ($000s)	Proved Reserves	Proved Plus Probable Reserves
2017	516	516
2018	2,564	2,564
2019	2,610	2,610
2020	-	-
2021	-	-
Thereafter	-	-
Total Undiscounted	5,690	5,690
Total Discounted at 10%	4,963	4,963

AGGREGATE

	Forecast Prices and Costs	
Year ($000s)	Proved Reserves	Proved Plus Probable Reserves
2017	3,572	4,043
2018	11,926	26,254
2019	3,298	23,778
2020	-	5,724
2021	-	3,287
Thereafter	140	1,192
Total Undiscounted	18,936	64,278
Total Discounted at 10%	16,516	52,418

Notes:

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

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

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

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

(5) Estimated future abandonment and reclamation costs related to a property have been taken into account by McDaniel in determining reserves that should be attributed to a property. Reasonable estimated future well abandonment costs were deducted in determining the aggregate future net revenue. No allowance was made, however, for reclamation of well sites not assigned reserves or the abandonment and reclamation of any facilities.

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

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

Reconciliation of Changes in Reserves

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

CANADA

	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			CONVENTIONAL NATURAL GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2015	5,123	2,110	7,233	4,298	4,179	8,477	8,451	5,447	13,898
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	230	(71)	159	(36)	(1,384)	(1,420)	865	(563)	302
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(3,606)	(1,435)	(5,041)	-	-	-	(1,655)	(899)	(2,554)
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(491)	-	(491)	(421)	-	(421)	(1,280)	-	(1,280)
December 31, 2016	**1,256**	**604**	**1,860**	**3,841**	**2,795**	**6,636**	**6,381**	**3,985**	**10,366**

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

UNITED STATES

	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			CONVETIONAL NATURAL GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2015	2,146	573	2,719	-	-	-	-	-	-
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	(32)	13	(19)	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(140)	-	(140)	-	-	-	-	-	-
December 31, 2016	**1,974**	**586**	**2,560**	-	-	-	-	-	-

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

AGGREGATE

	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			CONVENTIONAL NATURAL GAS		
FACTORS	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2015	7,269	2,683	9,952	4,298	4,179	8,477	8,451	5,447	13,898
Extensions & Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	198	(58)	140	(36)	(1,384)	(1,420)	865	(563)	302
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(3,606)	(1,435)	(5,041)	-	-	-	(1,655)	(899)	(2,554)
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(631)	-	(631)	(421)	-	(421)	(1,280)	-	(1,280)
December 31, 2016	**3,230**	**1,190**	**4,420**	**3,841**	**2,795**	**6,636**	**6,381**	**3,985**	**10,366**

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by McDaniel in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. In our practice, proved undeveloped reserves tend to be those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from our gathering systems. In addition, such reserves may relate to planned infill drilling locations. Probable undeveloped reserves may be reserves tested or indicated by analogy to be productive, infill drilling location and lands contiguous to production. In either case, the majority of undeveloped reserves are planned to be on stream within a two-year time frame. Undeveloped proved and probable reserves represent only about 18 percent of our proved and probable reserves.

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

Proved Undeveloped Reserves

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

Year	**Light and Medium Oil (Mbbl)**		**Heavy Oil (Mbbl)**		**Natural Gas (MMcf)**		**NGLs (Mbbl)**	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2014	412	696	100	100	6	288	-	-
2015	118	877	-	1,188	16	307	1	1
2016	-	254	-	100	16	8	1	-

A total of 354 Mbbl of oil 8 MMcf of gas and nil Mbbl of NGLs were assigned as proved undeveloped reserves in the McDaniel Report at December 31, 2016, representing five percent of our total proved reserves. In estimating future net revenue McDaniel reviewed our future development plans in order to estimate and deduct future development costs. Therefore the future development costs as set out under "*Future Development Costs*" are consistent with our future development plans if future prices meet or exceed the McDaniel price forecast. The proved undeveloped reserves are generally associated with infill/development drilling locations supported by recent drilling results and offset well data. The largest portion of the capital associated with developing proved undeveloped reserves is expected to be spent in 2017, with carryover into 2018. Within the McDaniel Report 63 percent of the capital is scheduled to be spent over the next two years.

Probable Undeveloped Reserves

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

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2014	156	722	100	2,136	37	1,253	-	6
2015	94	790	-	3,110	8	1,526	-	13
2016	-	301	-	1,448	-	838	-	11

A total of 1,749 Mbbl of oil, 838 MMcf of gas and 11 Mbbl of NGLs were assigned as gross probable undeveloped reserves in 2016, representing approximately 26 percent of our total probable reserves or 17 percent of our total proved plus probable reserves. The majority of the probable reserves assignment for us relates to properties which have proved producing reserves assigned. The bulk of the probable undeveloped reserves are assigned to projects which are actively underway or are contemplated in our forecasted capital programs based on the McDaniel price forecast. Of the total future development costs assigned in the McDaniel Report for probable undeveloped reserves 32 percent are forecast to be spent in 2017 and 2018.

Significant Factors or Uncertainties Affecting Reserves Data

Our reserves have been evaluated in accordance with NI 51-101 by McDaniel, an independent engineering firm, effective December 31, 2016. Our audit and reserves committee has reviewed the scope and methodology of McDaniel's evaluation; any significant new discoveries, additions, revisions and acquisitions, and reviewed the assumptions and consistency with prior years.

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

Changes in future commodity prices relative to the forecasts provided under "*Pricing Assumptions*" above could have a negative impact on our reserves and in particular the development of our undeveloped reserves unless future development costs are adjusted in parallel. Other than the foregoing and the factors disclosed or described in the tables above our evaluated oil and gas properties have no material extraordinary risks or uncertainties beyond those which are inherent in an oil and gas producing company as described in our management's discussion and analysis relating to our 2016 annual audited consolidated financial statements under the heading "*Risk Factors*" and "*Outlook*", which is incorporated herein by reference. See also "*Risk Factors – Risks Relating to Our Business and Operations*" below.

Abandonment and Reclamation Costs

In connection with our operations, we will incur abandonment and reclamation costs for surface leases, wells, facilities and pipelines. We budget for and recognize as a liability the estimated present value of the future decommissioning liabilities associated with our property, plant and equipment. Our overall abandonment and reclamation costs include all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard imposed by the applicable government or regulatory authorities. These costs were estimated using our experience conducting abandonment and reclamation programs. We review suspended or standing wells for reactivation, recompletion or sale and conduct systematic abandonment programs for those wells 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. There are no unusually significant abandonment and reclamation costs associated with our properties with attributed reserves.

We will be liable for our share of ongoing environmental obligations and for the ultimate reclamation of the surface leases, wells, facilities, and pipelines held by it upon abandonment. Ongoing environmental obligations are expected to be funded out of cash flow.

We estimate the costs to abandon and reclaim all of our producing and shut in wells, facilities, and pipelines. Using public data and our own experience, we estimate the amount and timing of future abandonment and reclamation expenditures at an operating area level. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment cost history.

As at December 31, 2016, we had 638.7 net wells capable of production for which we expect to incur abandonment and/or reclamation costs.

Estimated future abandonment and reclamation costs related to well abandonment and reclamation of 257.7 existing and future net wells have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregated future net revenue therefrom. No allowance was made, however, for the abandonment and reclamation of any pipelines, facilities or wells without reserves.

The additional liability associated with the 381.0 net wells not assigned reserves by McDaniel in the McDaniel Report, pipelines and facility reclamation costs, which were estimated to be $39.17 million (undiscounted) as at December 31, 2016, were not deducted in estimating future net revenue in the McDaniel Report.

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

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted ($000s)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($000s)
Total liability as at December 31, 2016	31,253	4,499
Anticipated to be paid in 2017	-	-
Anticipated to be paid in 2018	-	-
Anticipated to be paid in 2019	-	-

We have estimated the net present value of our total asset retirement obligations to be $66.75 million as at December 31, 2016 based on a total future liability of $70.42 million. The future net revenues disclosed in this Annual Information Form based on the McDaniel Report do not contain an allowance for abandonment and reclamation costs for batteries, nor do they provide for offsetting salvage values. The McDaniel Report deducted $31.25 million (undiscounted) and $4.50 million (10 percent discount using forecast prices and costs for proved and probable reserves) for abandonment and reclamation costs in estimating the future net revenue disclosed in this Annual Information Form.

Other Oil and Gas Information

Oil and Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2016. The term "net", when used to describe our share of production, means the total of our working interest share before deduction of royalties owned by others. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2016. **Estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.**

Our major properties are concentrated within Alberta in Canada and in North Dakota in the United States. Each region offers a large undeveloped land base, a vast seismic database, and significant ownership and operatorship in production facilities.

Alberta Plains

Our Alberta Plains core area holds 77 percent of our proved and probable oil and liquids reserves at year end 2016 and provided 61 percent of our 2016 oil and liquids production, primarily from the Taber South, Little Bow, and Bellshill Lake properties.

The Bellshill Lake and Taber South properties are expected to require additional wells to optimally exploit. The McDaniel Report has booked five undeveloped Bellshill Lake vertical development locations and three horizontal locations in Taber South.

The largest and most important property in this core area is Little Bow with its tertiary oil recovery opportunities plus a number of waterflood and production optimization projects. Over the last few years, we have assembled assets at Little Bow through a number of property and corporate acquisitions, which also consolidated our position in the ASP project. The Little Bow ASP tertiary oil recovery project entails the injection of chemicals in a dilute water solution into a partially depleted reservoir to recover incremental oil reserves.

In 2012, we received Alberta Energy Regulator approval and substantially completed the detailed engineering and the procurement of long-lead-time equipment for the Little Bow Upper Mannville I and P pool ASP project. During 2013, substantially all of the field construction was completed and final project commissioning commenced in the first quarter of 2014. The McDaniel Report has assigned 4.17 MMbbl of proved and probable oil and liquids reserves to the Little Bow ASP (Phase 1 and 2) project.

In March 2014, we commenced the injection of large volumes of dilute chemical solution into the partially depleted Little Bow Mannville I pool to recover incremental oil reserves. At December 31, 2016 a total of 7.0 million barrels of ASP solution has been injected into the first phase of the project. This injection volume represents approximately three quarters of target ASP volume. Due to low commodity pricing, full ASP injection was suspended in late March 2016. Since then approximately 3.3 million barrels of polymer solution has been injected. A polymer solution is utilized to maintain the integrity of oil banks in anticipation of return to full ASP injection when financial conditions improve sufficiently.

In late April 2015, we received formal approval from the Alberta Department of Energy for royalty relief under the *Enhanced Oil Recovery Royalty Regulations* for the Little Bow ASP Project. With this approval, wells within the Little Bow phase 1 scheme area will receive a five percent Alberta Crown oil royalty rate for a period of up to 10 years. The Alberta Modernized Royalty Framework released on January 29, 2016 does not directly affect the prior approvals under the existing Enhanced Oil Recovery Program. The Government of Alberta has committed to developing cost allowance programs for enhanced oil recovery schemes initiated after January 1, 2017. See "*Industry Conditions – Royalties and Incentives – Alberta – Alberta Enhanced Oil Recovery Program*".

In March 2016, we suspended the alkali and surfactant injections into the Little Bow ASP Project in an effort to conserve funds. In the third quarter of 2016, we modified the ASP project's depletion strategy by shutting in higher water cut producers in under treated areas in order to reduce the polymer costs required to treat the re-injected water volumes. This strategy will maintain and produce the oil banks that have already been formed in the reservoir while preserving our ability to re-initiate the alkaline surfactant injections in the under treated areas, once higher oil prices and improved financial conditions permit.

Williston Basin

We have a long and profitable history in our Williston Basin core area, which encompassed the Southeast Saskatchewan assets that were sold in the Saskatchewan Disposition, and three counties of North Dakota. Our remaining assets in the Williston Basin located in North Dakota hold 23 percent of our proved and probable oil and liquids reserves.

Based on our geophysical, geological and reservoir engineering work, we have identified 18 undeveloped Mississippian locations in the Williston Basin. These locations are characterized by lower permeability reservoirs that are generally partially pressure supported by either weak aquifers or, in some cases, by mature waterfloods, and production from these locations will be characterized by relatively low initial rates, moderately high water cuts, and shallow production declines. In recent years, we have allocated most of our capital budget to the Little Bow ASP project, and virtually no drilling capital has been directed to the drainage locations at the Mackobee Coulee and Haas, properties. The McDaniel Report has booked only four of these undeveloped Williston Basin horizontal drainage locations.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2016.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Canada								
British Columbia	-	-	-	-	-	-	3.0	1.4
Alberta	212.0	172.2	233.0	188.9	81.0	39.2	142.0	79.1
Saskatchewan	-	-	9.0	4.3	37.0	18.5	91.0	42.1
United States								
North Dakota	83.0	82.3	11.0	10.8	-	-	-	-
Total	295.0	254.5	253.0	204.0	118.0	57.7	236.0	122.6

Notes:

(1) Well counts are based on wellbores.
(2) We have no offshore wellbores.

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2016.

	Undeveloped Acres (1)	
(thousand acres)	Gross	Net
Alberta	76	36
British Columbia	5	3
Saskatchewan	7	2
United States	4	4
Total	92	45

Notes:

(1) None of our undeveloped lands have reserves attributed to them.
(2) Rights to explore, develop and exploit 8,466 net acres of our undeveloped land holdings in Canada and 2,045 net acres of our undeveloped land holdings in the United States are scheduled to expire by December 31, 2017.
(3) 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.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

Our business model focuses on sustainable low decline production with little capital allocated to the acquisition, exploration or development of our properties with no attributed reserves. However, our decision to develop our properties with no attributed reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs and royalty regimes all of which are beyond our control. See "*Significant Factors and Uncertainties Affecting Reserves Data – Abandonment and Reclamation Costs*" and "*Risk Factors*".

Forward Contracts

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

For details of our material commitments to sell natural gas and crude oil that were outstanding at December 31, 2016 see Note 26 to our 2016 annual audited consolidated financial statements, which is incorporated herein by reference.

Tax Horizon

We did not pay Canadian or United States income taxes in 2016.

We are a taxable entity under the *Income Tax Act* (Canada); however, based on the current forward commodity strip, we do not expect to pay cash taxes in Canada before 2018.

Costs Incurred

The following table summarizes capital expenditures related to our activities for the year ended December 31, 2016.

($ million)	**Canada**	**United States**	**Total**
Property Acquisition/(Disposition) Costs:			
Proved Properties [1]	(92.04)	-	(92.04)
Unproved Properties	1.91	0.02	1.93
Corporate Acquisitions	(0.12)	-	(0.12)
Development Costs [2]	4.62	0.06	4.68
Exploration Costs [3]	0.36	0.06	0.42
Total	(85.27)	0.14	(85.13)

Notes:

(1) Acquisitions are net of disposition of properties.
(2) Development and facilities expenditures.
(3) Cost of land acquired, geological and geophysical capital expenditures and drilling costs for 2016 exploration wells drilled.

Exploration and Development Activities

We did not participate in any exploratory wells during the year ended December 31, 2016. We did not participate in any development wells during the year ended December 31, 2016.

In 2017, we are budgeted to invest approximately $7.8 million in our core areas, which is comprised of a net $5.1 million of field capital and $2.7 million of ASP related expenditures. The 2017 ASP budget is comprised of $2.7 million of chemical costs and only minimal spending of general ASP exploitation expenditures. The 2017 capital budget does not include any capital for acquisitions, which may be pursued on an opportunistic basis. For more details regarding our most important current exploration and development activities for 2017 see, *"Other Oil and Gas Information – Oil and Gas Properties*" above.

Production Estimates

The following table sets out the volumes of 2017 gross production estimated in the McDaniel Report for the year ended December 31, 2016, which is reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data and Other Oil and Natural Gas Information*".

CANADA	**Light and Medium Crude Oil**	**Conventional Natural Gas**	**Natural Gas Liquids**	**Heavy Crude Oil**	**BOE**
	(bbl/d)	(Mcf/d)	(bbl/d)	(bbl/d)	(boe/d)
Total Proved	475	2,658	26	1,028	1,971
Total Probable	30	449	1	18	125
Total Proved Plus Probable	505	3,107	27	1,046	2,096

UNITED STATES	**Light and Medium Crude Oil**	**Conventional Natural Gas**	**Natural Gas Liquids**	**Heavy Crude Oil**	**BOE**
	(bbl/d)	(Mcf/d)	(bbl/d)	(bbl/d)	(boe/d)
Total Proved	363	-	-	-	363
Total Probable	5	-	-	-	5
Total Proved Plus Probable	368	-	-	-	368

Production History and Prices Received

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

CANADA

	Quarter Ended			
	2016			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production:				
Conventional Natural Gas (Mcf/d)	2,983	3,392	3,583	4,037
Light and Medium Crude Oil (bbl/d)	514	1,318	1,728	1,814
Heavy Crude Oil (bbl/d)	1,050	1,161	1,187	1,208
Natural Gas Liquids (bbl/d)	41	61	83	87
Combined (boe/d)	2,102	3,105	3,595	3,781
Average Price Received: (1)				
Conventional Natural Gas ($/Mcf)	3.03	2.20	1.16	1.64
Light and Medium Crude Oil ($/bbl)	49.86	47.78	45.68	31.99
Heavy Crude Oil ($/bbl)	44.75	38.96	38.76	23.57
Natural Gas Liquids ($/bbl)	37.91	21.61	18.99	20.20
Combined ($/boe)	39.59	37.68	36.36	25.09
Royalties Paid:				
Conventional Natural Gas ($/Mcf)	0.13	(0.14)	(0.38)	0.12
Light and Medium Crude Oil ($/bbl)	8.02	7.52	7.26	4.34
Heavy Crude Oil ($/bbl)	2.20	1.99	1.53	0.99
Natural Gas Liquids ($/bbl)	1.34	1.28	0.87	1.52
Combined ($/boe)	3.27	3.81	3.63	2.57
Production Costs:				
Conventional Natural Gas ($/Mcf)	2.91	2.81	2.41	2.58
Light and Medium Crude Oil ($/bbl)	21.97	20.35	20.39	21.46
Heavy Crude Oil ($/bbl)	21.70	16.71	16.64	16.15
Natural Gas Liquids ($/bbl)	18.39	9.27	8.15	13.84
Combined ($/boe)	20.69	18.14	17.89	18.53
Netback Received: (2)				

	Quarter Ended			
	2016			
	Dec. 31	Sept. 30	June 30	Mar. 31
Conventional Natural Gas ($/Mcf)	(0.00)	(0.48)	(0.86)	(1.07)
Light and Medium Crude Oil ($/bbl)	19.86	19.92	18.03	6.18
Heavy Crude Oil ($/bbl)	20.85	20.26	20.59	6.41
Natural Gas Liquids ($/bbl)	18.18	11.07	9.96	4.84
Combined ($/boe)	15.64	15.73	14.84	4.00

Notes:

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

UNITED STATES

	Quarter Ended			
	2016			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production:				
Conventional Natural Gas (Mcf/d)	-	-	-	-
Light and Medium Crude Oil (bbl/d)	347	375	415	395
Heavy Crude Oil (bbl/d)	-	-	-	-
Natural Gas Liquids (bbl/d)	-	-	-	-
Combined (boe/d)	347	375	415	395
Average Price Received: (1)				
Conventional Natural Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	49.66	45.31	43.42	27.32
Heavy Crude Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	49.66	45.31	43.42	27.32
Royalties Paid:				
Conventional Natural Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	12.22	11.15	10.18	6.60
Heavy Crude Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	12.22	11.15	10.18	6.60
Production Costs:				
Conventional Natural Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	27.34	19.91	15.37	20.86
Heavy Crude Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	27.34	19.91	15.37	20.86
Netback Received: (2)				
Conventional Natural Gas ($/Mcf)	-	-	-	-
Light and Medium Crude Oil ($/bbl)	10.10	14.25	17.87	(0.13)
Heavy Crude Oil ($/bbl)	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-
Combined ($/boe)	10.10	14.25	17.87	(0.13)

Notes:

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

AGGREGATE

	Quarter Ended			
	2016			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production:				
Conventional Natural Gas (Mcf/d)	2,983	3,392	3,583	4,037
Light and Medium Crude Oil (bbl/d)	861	1,693	2,143	2,209
Heavy Crude Oil (bbl/d)	1,050	1,161	1,187	1,208
Natural Gas Liquids (bbl/d)	41	61	83	87
Combined (boe/d)	2,449	3,480	4,010	4,176
Average Price Received: (1)				
Conventional Natural Gas ($/Mcf)	3.03	2.20	1.16	1.64
Light and Medium Crude Oil ($/bbl)	49.78	47.24	45.24	31.16
Heavy Crude Oil ($/bbl)	44.75	38.96	38.76	23.57
Natural Gas Liquids ($/bbl)	37.91	21.61	18.99	20.20
Combined ($/boe)	41.01	38.50	37.09	25.30
Royalties Paid:				
Conventional Natural Gas ($/Mcf)	0.13	(0.14)	(0.38)	1.64
Light and Medium Crude Oil ($/bbl)	9.71	8.32	7.83	31.16
Heavy Crude Oil ($/bbl)	2.20	1.99	1.53	23.57
Natural Gas Liquids ($/bbl)	1.34	1.28	0.87	20.20
Combined ($/boe)	4.54	4.60	4.31	25.30
Production Costs:				
Conventional Natural Gas ($/Mcf)	2.91	2.81	2.41	2.58
Light and Medium Crude Oil ($/bbl)	24.14	20.25	19.42	21.35
Heavy Crude Oil ($/bbl)	21.70	16.71	16.64	16.15
Natural Gas Liquids ($/bbl)	18.39	9.27	8.15	13.84
Combined ($/boe)	21.63	18.33	17.63	18.75
Netback Received: (2)				
Conventional Natural Gas ($/Mcf)	(0.00)	(0.48)	(0.86)	(1.07)
Light and Medium Crude Oil ($/bbl)	15.94	18.66	18.00	5.06
Heavy Crude Oil ($/bbl)	20.85	20.26	20.59	6.41
Natural Gas Liquids ($/bbl)	18.18	11.07	9.96	4.84
Combined ($/boe)	14.85	15.57	15.15	3.61

Notes:

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

The following table indicates our average daily production from our core areas for the year ended December 31, 2016.

	Conventional Natural Gas	Light and Medium Crude Oil	Heavy Crude Oil	Natural Gas Liquids	BOE
	(Mcf/d)	(bbl/d)	(bbl/d)	(bbl/d)	(boe/d)
Alberta Plains North	1,389	597	1	28	858
Alberta Plains South	1,883	4	1,150	15	1,483
Williston Basin	226	1,123	-	25	1,185
Total	3,498	1,724	1,151	68	3,526

Marketing Arrangements

Natural Gas

Most of our natural gas production was sold by spot sale contracts and Alberta index prices were received. In order to control and manage credit risk and ensure competitive bids, we engage with a number of reputable counterparties for our natural gas transactions. The integration and application of these strategies resulted in an average realized price (after realized risk management gains/losses) of $1.95 per Mcf in 2016 compared to $2.88 per Mcf in 2015.

Oil and Natural Gas Liquids

We sell our oil and natural gas liquids production to a variety of customers. This allows us to benefit from specific regional advantages while maintaining pricing and delivery flexibility. In general, we market our oil production with various purchasers under one month renewable contracts and receive posted reference prices with adjustments for quality and transportation. In 2016, our average realized oil and liquids price (after realized risk management gains/losses) was $41.47 per bbl compared to $59.51 in 2015.

Risk Management Activities

Our commodity price risk management policy, which is approved by the Board of Directors, allows for the sale of up to a certain percent of our estimated before royalty production volumes for each commodity for up to a 30 month period. For details of our risk management activities in 2016 see our management's discussion and analysis relating to our 2016 annual audited consolidated financial statements under the heading "*Risk Management Activities*", which is incorporated herein by reference.

Acquisitions and Dispositions

During 2016, we completed the 2016 Dispositions. See "*General Development of Our Business – History and Development – Developments in 2016*".

Social and Environmental Policy

We approach social responsibility and sustainable development by seeking a balance among economic, environmental and social issues while maintaining growth. We strive to find solutions to these issues that do not compromise the needs of future generations and place a high priority on preserving the quality of the environment, protecting the health and safety of our employees, contractors and the public in the communities in which we operate. Additionally, we actively participate in industry recognized programs that support our sustainable mindset.

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

Our environmental policy states that:

- Operating in an environmentally responsible manner is key to insuring our continued growth and the industry.

- Sound environmental management is an integral component of a good business plan. Environmental stewardship reduces costs and corporate liability. It enhances shareholder value, boosts employee morale and enhances our image in the eyes of regulators and the public.

- Managing our environmental responsibilities is a team effort requiring the commitment of management, employees and contractors.

- Preventing environmental damage is cheaper than repairing damage.

- An effective environmental program helps operations staff to understand and comply with environmental laws and regulations and to minimize the costs and liabilities associated with environmental damage. It helps meet the concerns of stakeholders that environmental issues are being managed properly and will provide a due-diligence defence in the event of an environmental incident.

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

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

OUR CAPITAL STRUCTURE

Share Capital

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

Common Shares

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

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

Holders of our Common Shares will be entitled in the event of our liquidation, dissolution or winding-up, whether voluntary or involuntary, or any other distribution of our assets among our Shareholders for the purpose of winding-up our affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes ranking in priority to the Common Shares in respect of a return of capital on dissolution, to share rateably, together with the holders of shares of any other class of our shares ranking equally with the Common Shares in respect of a return of capital on dissolution, in such of our assets as are available for distribution.

Preferred Shares

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

Board of Directors may at any time or from time to time change the rights, privileges, restrictions and conditions attached to unissued shares of any series of Preferred Shares; and (b) other than in the case of a failure to declare or pay dividends specified in any series of the Preferred Share, the voting rights attached to the Preferred Shares will be limited to one vote per Preferred Share at any meeting where the Preferred Shares and Common Shares vote together.

Credit Facility

In 2016, we used part of the proceeds to the 2016 Dispositions to eliminate our bank debt and the Credit Agreement was terminated.

Convertible Debentures

The Convertible Debentures were issued under and pursuant to the provisions of the Debenture Indenture. The following description of the Convertible Debentures is a summary of their material attributes and characteristics and is subject to the detailed provisions of the Debenture Indenture and is qualified in its entirety by reference to the Debenture Indenture which has been filed and are available on SEDAR at www.sedar.com.

General

The Convertible Debentures mature on December 31, 2019 and beginning April 1, 2017 will bear interest at an annual rate of 8.00% payable semi-annually in arrears on March 31 and September 30 in each year. Prior to April 1, 2017, the Convertible Debentures will bear interest at the previous annual rate of 6.00%.

Conversion Privilege

Each Convertible Debenture is convertible at the option of the holder into fully paid and non-assessable Common Shares at any time prior to 5:00 p.m. (Calgary time) on the earliest of: (i) the last business day immediately preceding their maturity and (ii) the last business day immediately preceding the date specified by us for redemption, in each case, at a conversion price of $1.25 per Common Share, representing a conversion rate of approximately 800 Common Shares per $1,000 principal amount of Convertible Debentures. The conversion price may be adjusted in certain circumstances as described in the Debenture Indenture.

Interest will be paid on conversion from up to, but not including, the date of conversion. The Convertible Debentures may not be converted on March 31 or September 30 or during the five business days preceding March 31 and September 30 in each year, as the registers of the Debenture Trustee will be closed during such periods. No fractional Common Shares will be issued on any conversion of the Convertible Debenture but in lieu thereof we will satisfy fractional interests by a cash payment equal to the current market price of any fractional interest.

Redemption and Purchase

The Convertible Debentures may not be redeemed by us before January 1, 2019, except in certain limited circumstances following a change of control and pursuant to the Put Right. On or after January 1, 2019 and prior to their maturity, the Convertible Debentures may be redeemed by us, in whole or in part from time to time, at our option on not more than 60 days' and not less than 30 days' prior written notice at a redemption price equal to the principal amount plus accrued and unpaid interest thereon, if any, provided that the current market price of the Common Shares on the date on which notice of redemption is given is not less than 125% of the conversion price. In the event that a holder of Convertible Debentures exercises their conversion right following a notice of redemption by us, the holder will be entitled to receive accrued and unpaid interest, in addition to the applicable number of Common Shares to be received on conversion, for the period from the last interest payment date up to, but not including, the date of conversion.

In the case of redemption of less than all of the Convertible Debentures, the Convertible Debentures to be redeemed will be selected by the Debenture Trustee on a pro rata basis or in such other manner as the Debenture Trustee deems equitable, subject to regulatory approvals.

In addition, we have the right to purchase Convertible Debentures for cancellation in the market, by tender or by private contract, at any time, subject to regulatory requirements.

Payment upon Redemption or at Maturity

On redemption or at maturity, as applicable, we are required to repay the indebtedness represented by the Convertible Debentures by paying to the Debenture Trustee an amount equal to the principal amount of the outstanding Convertible Debentures, together with accrued and unpaid interest thereon, if any, up to but not including the redemption date or the maturity date, as applicable. On redemption or at maturity, as applicable, we may, at our option, on not more than 60 days' and not less than 40 days' prior notice and subject to any required regulatory approvals, and provided that no event of default has occurred and is continuing, elect to satisfy our obligation to repay, in whole or in part, the principal amount of the Convertible Debentures which are to be redeemed or which have matured by issuing and delivering Common Shares to the holders of the Convertible Debentures in an amount equal to the principal amount of the Convertible Debentures divided by 95% of the current market price of the Common Shares. Any accrued and unpaid interest thereon will be paid in cash. In the event a holder of Convertible Debentures exercises its conversion rights following delivery of a notice of redemption by us, such holder shall be entitled to receive the applicable number of Common Shares to be received on conversion on the last business day immediately preceding the redemption.

No fractional Common Shares will be issued upon redemption or at maturity of the Convertible Debenture but in lieu thereof we will satisfy fractional interests by a cash payment equal to the current market price of any fractional interest.

Rank

The Convertible Debentures are subordinate to all Senior Indebtedness as more particularly described below under "*Subordination*". In the event of our insolvency, bankruptcy, liquidation, reorganization, dissolution or winding up, our assets would be made available to satisfy the obligations of the creditors of such Senior Indebtedness before being available to pay our obligations to the holders of Convertible Debentures. Accordingly, all or a substantial portion of our assets could be unavailable to satisfy the claims of the holders of Convertible Debentures.

Subordination

The payment of the principal and premium, if any, of, and interest on, the Convertible Debentures is subordinated and postponed, and subject in right of payment, to the full and final payment of all of our Senior Indebtedness. "**Senior Indebtedness**" is defined in the Debenture Indenture as all of our obligations, liabilities and indebtedness which would, in accordance with generally accepted accounting principles, be classified upon our consolidated balance sheet as our liabilities and, whether or not so classified, includes (without duplication): (a) our indebtedness for borrowed money; (b) our obligations evidenced by bonds, debentures, notes or other similar instruments; (c) our obligations arising pursuant or in relation to bankers' acceptances, letters of credit, letters of guarantee, performance bonds and surety bonds (including payment and reimbursement obligations in respect thereof) or indemnities issued in connection therewith; (d) our obligations under any swap, hedging or other similar contracts or arrangements; (e) our obligations under guarantees, indemnities, assurances, legally binding comfort letters or other contingent obligations relating to the Senior Indebtedness or other obligations of any other person which would otherwise constitute Senior Indebtedness within the meaning of this definition; (f) all of our indebtedness representing the deferred purchase price of any property including, without limitation, purchase money mortgages; (g) accounts payable to trade creditors; (h) all renewals, extensions and refinancing of any of the foregoing; (i) all declared but unpaid dividends or distributions; and (j) all costs and expenses incurred by or on behalf of any senior creditor in enforcing payment or collection of any such Senior Indebtedness, including enforcing any security interest securing the same but "Senior Indebtedness" does not include any indebtedness that would otherwise be Senior Indebtedness if it is expressly stated to be subordinate to or rank *pari passu* with the Convertible Debentures.

The Debenture Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation, reorganization or other similar proceedings relative to us, or to our property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding-up of us, whether or not involving insolvency or bankruptcy, or any marshalling of our assets and liabilities, then holders of Senior Indebtedness will receive payment in full before the holders of Convertible Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Convertible Debentures or any unpaid interest accrued thereon. The Debenture Indenture also provides that we will not make any payment, and the holders of the Convertible Debentures will not be entitled to demand, institute proceedings for the collection of, or receive any payment or benefit (including, without any limitation, by set-off, combination of accounts or realization of security or otherwise in any manner whatsoever) on account of indebtedness represented by the Convertible Debentures: (a) in a manner inconsistent with the terms (as they exist on the date of issue) of the Convertible Debentures; or (b) at any time when a default or an event of default has occurred under the Senior Indebtedness and is continuing or upon the acceleration of Senior Indebtedness, unless the Senior Indebtedness has been repaid in full.

Repurchase upon a Change of Control

Within 30 days following the occurrence of a Change of Control, we are required to make a cash offer to purchase all of the Convertible Debentures at a price equal to 100% of the principal amount thereof plus accrued and unpaid interest thereon. A "**Change of Control**" is defined in the Debenture Indenture to include: (i) an acquisition by a person or group of persons acting jointly or in concert (within the meaning of Multilateral Instrument 62-104 – *Take-Over Bids and Issuer Bids* ("**MI 62-104**") and in Ontario, the *Securities Act* (Ontario) and Ontario Securities Commission Rule 62-504 – *Take-Over Bids and Issuer Bids*) of ownership of, or voting control or direction over, more than 50% of the issued and outstanding Common Shares; or (ii) the sale or other transfer of all or substantially all of our consolidated assets, excluding a sale, merger, reorganization or other similar transaction if the previous holders of the Common Shares hold at least 50% of the voting control in such merged, reorganized or other continuing entity.

If Convertible Debentures representing 90% or more of the aggregate principal amount of the Convertible Debentures outstanding on the date of the giving of notice of the Change of Control are tendered for purchase following a Change of Control (other than Convertible Debentures held at the date of the take-over bid by or on behalf of the offeror, associates or affiliates of the offeror or any one acting jointly or in concert with the offeror), we have the right to redeem all of the remaining Convertible Debentures at the same price.

Cash Change of Control

In addition to the requirement for us to make a cash offer to purchase all of the Convertible Debentures in the event of a Change of Control, if a Change of Control occurs on or before maturity in which 10% or more of the consideration for the Common Shares in the transaction or transactions constituting a Change of Control consists of: (i) cash (other than cash payments for fractional Common Shares and cash payments made in respect of dissenters' appraisal rights); (ii) equity securities (including trust units, limited partnership units or other participating securities of a trust, limited partnership or similar entity) that are not traded or intended to be traded immediately following such transactions on a recognized stock exchange; or (iii) other property that is not traded or intended to be traded immediately following such transactions on a recognized stock exchange, then subject to regulatory approvals, holders of Convertible Debentures will be entitled to convert their Debentures, subject to certain limitations, and receive, subject to and upon completion of the Change of Control, in addition to the number of Common Shares they would otherwise be entitled to receive on conversion, an additional number of Common Shares per $1,000 principal amount of Convertible Debentures. The number of such additional Common Shares per $1,000 principal amount of Debentures will be determined by reference to the provisions of the Debenture Indenture based on the date on which the Change of Control becomes effective and the price paid per Common Share in the transaction constituting the Change of Control.

Interest Payment Election

Unless an Event of Default (as defined below) under the Debenture Indenture has occurred and is continuing, we may elect, from time to time, subject to applicable regulatory approval, to satisfy our obligation to pay all or any portion of the interest on the Convertible Debentures by delivering sufficient Common Shares to the Debenture Trustee for sale, to satisfy such obligation, and holders of the Convertible Debentures will be entitled to receive a cash payment equal to the interest payable from the proceeds of the sale of such Common Shares. The Debenture Indenture sets out the procedures to be followed by us and the Debenture Trustee in order to effect this election.

Events of Default

The Debenture Indenture provides that an event of default ("**Event of Default**") in respect of the Convertible Debentures will occur if certain events described in the Debenture Indenture occur, including if any one or more of the following described events has occurred and is continuing with respect to such Convertible Debentures: (i) failure for 30 days to pay interest on the Convertible Debentures when due; (ii) failure to pay principal or premium, if any (whether by payment in cash or delivery of Common Shares), on the Convertible Debentures when due, whether at maturity, upon redemption, on a change of control, by declaration or otherwise; (iii) default in the delivery, when due, of any Common Shares or other consideration, including any Make-Whole Premium (as defined below), payable upon conversion with respect to the Convertible Debentures, which default continues for 15 days; (iv) default in the observance or performance of any other covenant or condition of the Debenture Indenture and the failure to cure (or obtain a waiver for) such default for a period of 30 days after notice in writing has been given by the Debenture Trustee or from holders of not less than 25% of the aggregate principal amount of the Convertible Debentures specifying such default and requiring us to rectify or obtain a waiver for same; (v) certain events of bankruptcy, insolvency or reorganization of us under bankruptcy or insolvency laws; and (vi) if an event of default occurs or exists under any agreement evidencing indebtedness for borrowed money (other than non-recourse debt) of us and as a result of such event of default (a) indebtedness for borrowed money thereunder in excess of $10,000,000 has become due and payable before the date it would otherwise have been due and payable, and (b) the holders of such indebtedness are entitled to commence, and have commenced, the enforcement of security they hold for such indebtedness (if any) or the exercise of any other creditors' remedies to collect such indebtedness.

If an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and will, upon the request of holders of not less than 25% in principal amount of the then-outstanding Convertible Debentures declare the principal of (and premium, if any) and interest on all outstanding Convertible Debentures to be immediately due and payable. In certain cases, the holders of more than 50% of the principal amount of the Convertible Debentures then-outstanding may, on behalf of the holders of all Convertible Debentures, waive any Event of Default and/or cancel any such declaration upon such terms and conditions as such holders shall prescribe.

Offers for Convertible Debentures

The Debenture Indenture contains provisions to the effect that if an offer is made for the Convertible Debentures which is a take-over bid for the Convertible Debentures within the meaning of MI 62-104 and in Ontario, the *Securities Act* (Ontario) and Ontario Securities Commission Rule 62-504 if the Convertible Debentures were considered equity securities, and not less than 90% of the principal amount of the then-outstanding Convertible Debentures (other than Convertible Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Convertible Debentures held by those who did not accept the offer on the terms offered by the offeror.

Modification

The rights of the holders of Convertible Debentures may be modified in accordance with the terms of the Debenture Indenture. For that purpose, among others, the Debenture Indenture will contain certain provisions which make binding on all holders of outstanding Convertible Debentures, resolutions passed at meetings of the holders of outstanding Convertible Debentures by votes cast thereat by holders of not less than 66⅔% of the principal amount of the then-outstanding Convertible Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66⅔% of the principal amount of the then-outstanding Convertible Debentures. Under the Debenture Indenture, certain amendments of a technical nature or which are not prejudicial to the rights of the holders of the Convertible Debentures may be made to the Debenture Indenture without the consent of the holders of the Convertible Debentures.

DIRECTORS AND OFFICERS

Directors

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

Name and Municipality of Residence	Director Since	Principal Occupation
Craig H. Hansen Calgary, Alberta	1992	Our President & Chief Executive Officer since 1993. Mr. Hansen is also a Governor of the Canadian Association of Petroleum Producers where he is currently Chair of the Fiscal Executive Policy Group.
K. James Harrison (2) (3) Oakville, Ontario	1995	Mr. Harrison is our Chairman. He is the founder of K.J. Harrison & Partners Inc., a private client investment management firm in Toronto, Ontario. Prior to 2000, he was the Vice-Chairman and Chief Executive Officer of Connor Clark Ltd.
Kyle D. Kitagawa (1) (3) Calgary, Alberta	2001	Mr. Kitagawa brings over 25 years of experience in commodity trading, equity investing, and structured finance in energy and energy intensive industries. Prior to April 2003, he held senior executive positions in a global energy trading and capital corporation. Mr. Kitagawa has been an independent businessman since 2003. In addition, Mr. Kitagawa serves as Chairman of Canadian Energy Services & Technology Corp.
Geoffrey C. Merritt (1) (3) Calgary, Alberta	2009	Mr. Merritt has been an independent businessman since April, 2009. Mr. Merritt was the founder of Masters Energy Inc., a public exploration and production company, incorporated in 2003 and acquired by us in April 2009. From 1998 to 2003, Mr. Merritt was the President and CEO of Sunfire Energy Corporation, a public oil and gas company. Prior to 1998, Mr. Merritt was the Vice President and General Manager of the oil and gas division of Pembina Corporation. Mr. Merritt currently sits on the board of Perpetual Energy Inc.
Jim Peplinski (1) (2) (3) Calgary, Alberta	1997	Mr. Peplinski is the founder of Jim Peplinski Leasing Inc., a commercial vehicle lessor. Mr. Peplinski is also the VP Business Development of the Calgary Flames Hockey Club as well as an investor in real estate and oil and gas.
Ron Wigham (2) (3) Calgary, Alberta	2015	Mr. Wigham is an independent businessman and a director of Spur Resources Ltd. and Tourmaline Oil Corp. He retired in 2014 as Vice-Chairman of Peters and Company.

Name and Municipality of Residence	Director Since	Principal Occupation
Grant A. Zawalsky (2) Calgary, Alberta	2000	Mr. Zawalsky is the Managing Partner of Burnet, Duckworth & Palmer LLP (Barristers and Solicitors) where he has been a partner since 1994. Mr. Zawalsky holds a B.Comm and LL.B. from the University of Alberta and is a member of the Law Society of Alberta. Mr. Zawalsky currently sits on the board of directors of a number of private and public companies, including NuVista Energy Ltd., PrairieSky Royalty Ltd. and Whitecap Resources Inc., and is Corporate Secretary of ARC Resources Ltd., Bonavista Energy Corporation and RMP Energy Inc. Mr. Zawalsky is also a Governor of the Calgary Petroleum Club.

Notes:

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

Officers

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

Name and Municipality of Residence	Officer Since	Office
Craig H. Hansen Calgary, Alberta	1992	President & Chief Executive Officer.
Leslie E. Burden Calgary, Alberta	2013	Vice President, Land since February, 2013; prior thereto our Manager, Land Negotiations and Manager, Land since 2010 and prior thereto Manager, Land at Masters Energy Inc. from 2005.
Randolph J. Doetzel Calgary, Alberta	2011	Vice President, Operations since June, 2011; prior thereto, our Production Manager, Williston Basin since January, 2009. Prior thereto, he held various executive, management and engineering positions at Cobalt Energy Ltd., Harvest Operations Corp., Apache Canada Ltd., and Samson Canada Ltd.
Christopher M. Hustad Calgary, Alberta	2013	Vice President, Development since November, 2016; prior thereto, our Vice President, Alberta Plains South since February, 2013. Prior thereto, Manager Exploitation, Alberta Plains South since August, 2008. Prior thereto, various management and engineering positions at Talisman Energy Inc.
William T. Cromb Calgary, Alberta	2016	Interim Chief Financial Officer since November 15, 2016; prior thereto, he held financial positions with Provident Energy Trust, Beau Canada Exploration, North West Upgrading and Canterra Energy.

As at March 15, 2017, our directors and officers, as a group, beneficially owned, controlled or directed, directly or indirectly, 3,778,825 Common Shares or approximately 12.3 percent of our issued and outstanding Common Shares. Our directors and officers also beneficially owned, controlled or directed, directly or indirectly $470,000 principal amount of Convertible Debentures.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

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

None of our directors or executive officers (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities to affect materially our control is, as of the date of this Annual Information Form, or has been, within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets. In addition, none of our directors or executive officers (nor any personal holding company of any such persons), or shareholder holding a sufficient number of our securities to materially affect the control of us has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

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

Conflicts of Interest

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

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

AUDIT AND RESERVES COMMITTEE INFORMATION

Audit and Reserves Committee Mandate and Terms of Reference

The Mandate of our audit and reserves committee is attached hereto as Schedule "C". The members of our audit and reserves committee are Kyle D. Kitagawa, Geoffrey C. Merritt and Jim Peplinski.

Composition of the Audit and Reserves Committee

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

Relevant Education and Experience

Name	Relevant Education and Experience
Kyle D. Kitagawa (Audit and Reserves Committee Chairman)	Mr. Kitagawa brings over 25 years of experience in commodity trading, equity investing, and structured finance in energy and energy intensive industries. Prior to April 2003, he held senior executive positions in a global energy trading and capital corporation. Mr. Kitagawa has been an independent businessman since 2003. In addition, Mr. Kitagawa serves as Chairman of Canadian Energy Services & Technology Corp. Mr. Kitagawa holds a Master of Business Administration degree from Queen's University, a Bachelor of Commerce from the University of Calgary and is a Chartered Accountant.
Jim Peplinski	Mr. Peplinski is the founder of Jim Peplinski Leasing Inc., a commercial vehicle lessor. Mr. Peplinski is also the VP Business Development of the Calgary Flames Hockey Club as well as an investor in real estate and oil and gas.
Geoffrey C. Merritt	Mr. Merritt has over 30 years of experience in the upstream oil and gas sector. In 2003, he founded Masters Energy Inc., a public exploration and production company, which was acquired by Zargon in April 2009. From 1998 to 2003, Mr. Merritt was the President and Chief Executive Officer of Sunfire Energy. Prior to 1998, he was the Vice President and General Manager of the oil and gas division of Pembina Corporation. He currently sits on the board of Perpetual Energy Inc. Mr. Merritt received a Bachelor of Science in Chemical Engineering from the University of Alberta in 1978 and is a graduate of the Harvard Business School.

Pre Approval Policies and Procedures

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

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditors, including expenses, in each of the last two fiscal years for audit services were $192,895 in 2016 and $231,363 in 2015.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by our external auditors, including expenses for tax compliance, tax advice and tax planning were $81,534 in 2016 and $92,293 in 2015.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by our auditors other than services reported above were $30,663 in 2016 and $30,663 in 2015.

DIVIDENDS

We have historically made monthly dividend payments to our Shareholders on the 15th day of each month or the first business day following the 15th day. The record date for any dividend was the last business day of the month preceding the dividend date or such other date as may be determined by our Board of Directors. All of these were designated as "eligible dividends" for Canadian income tax purposes.

On November 11, 2015, as a result of volatile, uncertain and exceptionally low oil prices, we suspended our monthly dividend until further notice.

We may reinstate dividend payments in the future. Actual future cash dividends, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. Our Board of Directors cannot provide assurance that cash flow will be available for distribution to Shareholders in the amounts anticipated or at all. See "*Risk Factors*".

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

Our ability to make cash dividends to Shareholders may be directly or indirectly affected in certain events as a result of certain restrictions, including the solvency tests in the *Business Corporations Act* (Alberta).

In November of 2015, we suspended our dividend. The tables indicate the monthly cash dividends declared by us in 2015 and 2014.

For the Month Ended	Dividends per Common Share	Payment Date
January 31, 2015	$0.03	February 17, 2015
February 28, 2015	$0.03	March 16, 2015
March 31, 2015	$0.03	April 15, 2015
April 30, 2015	$0.03	May 15, 2015
May 31, 2015	$0.03	June 15, 2015
June 30, 2015	$0.03	July 15, 2015
July 31, 2015	$0.01	August 17, 2015
August 31, 2015	$0.01	September 15, 2015
September 30, 2015	$0.01	October 15, 2015
October 31, 2015	$0.01	November 16, 2015
November 30, 2015	-	-
December 31, 2015	-	-
Total	$0.22	

For the Month Ended	Dividends per Common Share	Payment Date
January 31, 2014	$0.06	February 18, 2014
February 28, 2014	$0.06	March 17, 2014
March 31, 2014	$0.06	April 15, 2014
April 30, 2014	$0.06	May 15, 2014
May 31, 2014	$0.06	June 16, 2014
June 30, 2014	$0.06	July 15, 2014
July 31, 2014	$0.06	August 15, 2014
August 31, 2014	$0.06	September 15, 2014
September 30, 2014	$0.06	October 15, 2014
October 31, 2014	$0.06	November 17, 2014
November 30, 2014	$0.06	December 15, 2014
December 31, 2014	$0.06	January 15, 2015
Total	$0.72	

MARKET FOR SECURITIES

Common Shares

The Common Shares are listed and posted for trading on the TSX under the trading symbol "ZAR". The Common Shares commenced trading on the TSX on January 7, 2011 following completion of the Arrangement. The following table sets forth the high and low trading prices and the aggregate volume of trading of the Common Shares, as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2016			
January	1.00	0.45	2,839,463
February	0.60	0.35	2,076,637
March	0.79	0.46	2,039,766
April	0.78	0.60	2,369,747
May	0.65	0.47	897,275
June	0.58	0.43	1,060,802
July	0.68	0.43	2,513,533
August	1.05	0.58	2,390,053
September	1.00	0.75	1,681,921
October	0.87	0.68	2,571,014
November	0.78	0.62	2,154,356
December	0.83	0.70	1,784,075
2017			
January	0.87	0.70	1,165,317
February	0.88	0.70	1,089,345
March (1 – 15)	0.82	0.68	681,576

Convertible Debentures

The Convertible Debentures are listed and posted for trading on the TSX under the trading symbol "ZAR.DB". The Convertible Debentures commenced trading on the TSX on May 1, 2012. The following table sets forth the high and low trading prices and the aggregate volume of trading of the Convertible Debentures, as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2016			
January	42.62	21.99	17,710
February	32.00	24.50	7,850
March	40.01	25.73	10,410
April	39.10	29.75	9,620
May	42.00	34.00	16,940
June	54.25	42.00	21,540
July	85.00	49.99	32,750
August	81.00	73.49	38,840
September	85.00	79.00	18,140
October	85.00	82.00	8,600
November	84.00	77.00	16,810
December	88.00	78.80	11,890
2017			
January	94.00	88.01	28,170
February	93.01	89.51	26,740
March (1 - 15)	92.50	90.60	15,990

Following the completion of the redemption pursuant to the Put Right and the Amendments to the Debenture Indenture, the Convertible Debentures will begin trading on the TSX under the symbol "ZAR.DB.A". The Convertible Debentures are expected to begin trading under the new symbol on April 3, 2017.

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 and Alberta all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect our operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in Alberta.

Pricing and Marketing

Oil

In Canada, producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The 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 license from the National Energy Board. The National Energy Board underwent a consultation process to update the regulations governing the issuance of export licenses. The updating process was necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (Canada) (the "***Prosperity Act***") which received Royal Assent on June 29, 2012. The *Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations* came into effect on July 31, 2015 and provides the requirement for obtaining long-term licenses.

Natural Gas

Canada'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, 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, Intercontinental Exchange or the New York Mercantile Exchange 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 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 per day) must be made pursuant to a National Energy Board order. Natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas require an exporter to obtain an export license from the National Energy Board.

The North American Free Trade Agreement

The North American Free Trade Agreement among the governments of Canada, the United States and Mexico came into force 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. The new administration in the United States has indicated an intention to seek renegotiation of the North American Free Trade Agreements, the impact of which on the oil and gas industry is uncertain.

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 where the Crown does not hold mineral rights 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.

The Canadian federal government has signaled that it will, *inter alia*, phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing stringent reviews for pipelines, and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

In Alberta, the Crown owns 81% of the province’s mineral rights. The remaining 19% are ‘freehold’ mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies. Provincial government royalty rates apply to Crown-owned mineral rights. On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta. The Modernized Royalty Framework formally took effect on January 1, 2017 for wells drilled after this date. Wells drilled prior to January 1, 2017 will continue to be governed by the "New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) for a period of 10 years until January 1, 2027. The Modernized Royalty Framework is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on total depth, length and proppant placed). The new royalty rate for Pre-Payout under the Modernized Royalty Framework will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the New Royalty Framework. In the Mature phase of the Modernized Royalty Framework, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently the equivalent of 94 m^3 (40 barrels of oil equivalent per day or 345,000 m^3 of gas per month), the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, that came into effect on January 1, 2017, are a part of the Modernized Royalty Framework, and account for the higher costs associated with enhanced recovery methods and with developing emerging resources in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the Alberta Energy Regulator.

Oil sands projects are also subject to Alberta's royalty regime. The Modernized Royalty Framework does not change the oil sands royalty framework, however, the Government of Alberta plans to increase transparency in the method and figures by which the royalties are calculated. 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 between 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.

Currently, producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to the New Royalty Framework until January 1, 2027. Royalty rates for conventional oil are set by a single sliding scale 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 depends on the price of each of the components of the gas stream, the productivity of the well, its acid gas factor and the depth of the producing zone. These factors are employed on a sliding scale formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36% and a minimum royalty rate of 5%.

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 lands where the Crown does not hold the rights to mines and minerals 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 freehold 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. These initiatives apply to wells drilled before January 1, 2017, for a 10 year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months 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 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.

Alberta Enhanced Hydrocarbon Recovery Program

The Alberta government continues to encourage the use of enhanced oil recovery methods to promote incremental production and generate additional royalties and other benefits to Albertans. Enhanced hydrocarbon recovery methods use fluid injection such as chemicals (which includes ASP projects), hydrocarbons, CO2 or nitrogen allowing additional recovery. To promote these recovery techniques, the Enhanced Hydrocarbon Recovery Program was implemented as of January 1, 2017 replacing its predecessor, the Enhanced Oil Recovery Program. Under the program, after receiving approval from the Alberta Energy Regulator, the royalty rate for crude oil, natural gas, and natural gas liquids is set at a flat five percent for a period of up to 90 months. The duration of the fixed five percent royalty rate is dependent on the recovery methods used and the estimated additional amount of hydrocarbons that can be recovered using enhanced recovery methods. The Enhanced Hydrocarbon Recovery Program applies to applications made to the Alberta Energy Regulator on or after October 23, 2016. In late April 2015, we received formal approval from the Alberta Department of Energy for royalty relief under the Enhanced Oil Recovery Royalty Regulations for the Little Bow ASP Project. Approved applications made under the Enhanced Oil Recovery Program will continue to be effective until their benefit period ends or until the Enhanced Oil Recovery Program terminates on December 31, 2026. After two years, the approaches for determining the royalty benefit periods for the Enhanced Hydrocarbon Recovery Program will be reviewed, and possibly revised, to better align with the Modernized Royalty Framework's cost allowance approach.

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in Alberta. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses, 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.

The province of Alberta 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 issued after January 1, 2009 at the conclusion of the primary term of the lease or license.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, 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. The regulatory regimes set 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 licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

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

On June 20, 2016, the Federal Government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the National Energy Board, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An Expert Panel has been convened and is expected to complete its work by March 31, 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the Panel's report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the Federal Government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The Federal Government has not provided any indication on what changes—if any—will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

In a further development, on November 29, 2016, the Government of Canada announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast. It is unclear how the proposed moratorium may affect ongoing LNG export projects currently under consideration and development. On the same day, the Government of Canada also approved, subject to a number of conditions, the Trans Mountain Pipeline system expansion backed by Kinder Morgan Canada as well as the replacement of Enbridge Inc.'s plan to replace its Line 3 pipeline system, while also rejecting Enbridge Inc.'s proposed Northern Gateway project. On January 11, 2017, the Government of British Columbia confirmed that the conditions to the approval of the Trans Mountain Pipeline have been satisfied. Additionally, the new administration in the United States has indicated a willingness to revisit other pipeline projects that had been previously rejected.

Alberta

The Alberta Energy Regulator is the single regulator responsible for all energy development in Alberta. The Alberta Energy Regulator ensures the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. 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 a single regulator is 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.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System. The Integrated Resource Management System method to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities, by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the Alberta Energy Regulator is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office and the Land Use Secretariat.

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, licences, 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. The 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 oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands 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, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands 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.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan which came into force on September 1, 2014. The South Saskatchewan Regional Plan is the second regional plan developed under the Alberta Land Use Framework. The South Saskatchewan Regional Plan covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The South Saskatchewan Regional Plan creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to the Lower Athabasca Regional Plan, the South Saskatchewan Regional Plan will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

Phase 1 Consultation of the North Saskatchewan Region Plan has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The North Saskatchewan Region Plan is located in central Alberta and is approximately 85,780 square kilometres in size and affects activities in central Alberta, and encompasses an area between the province's borders with British Columbia and Saskatchewan. The Upper Peace Region Plan, Lower Peace Region Plan, Red Dear Region Plan and Upper Athabasca Region Plan have not been started.

Liability Management Rating Programs

In Alberta, the Alberta Energy Regulator administers 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. Alberta's *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 or is unable to meet its obligations. 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 licensees 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 assets to deemed liabilities 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. The Alberta Energy Regulator publishes the liability management rating for each licensee on a monthly basis.

Made effective in three phases, from May 1, 2013 to August 1, 2015, 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. The changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed assets to deemed liabilities under the Licensee Liability Rating Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On June 20, 2016, the Alberta Energy Regulator issued *Bulletin 2016-16, Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("***Bulletin 16***") in an urgent response to a decision from the Alberta Court of Queen's Bench, which is currently under appeal with the Court of Appeal of Alberta. In *Redwater Energy Corporation (Re)*, 2016 ABQB 278 ("***Redwater***"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the *Oil and Gas Conservation Act* and the *Bankruptcy and Insolvency Act*, and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the Alberta Energy Regulator's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the *Bankruptcy and Insolvency Act*. *Bulletin 16* provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. Three changes were implemented to minimize the risk to Albertans:

1. The Alberta Energy Regulator will consider and process all applications for licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licences* as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licencee eligibility approval if appropriate in the circumstances.
2. For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the Alberta Energy Regulator may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.
3. As a condition of transferring existing Alberta Energy Regulator licences, approvals, and permits, the Alberta Energy Regulator will require all transferees to demonstrate that they have a liability management rating, being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer.

In order to clarify and revise the interim rules in *Bulletin 16*, the Alberta Energy Regulator issued *Bulletin 2016-21: Revision and Clarification on Alberta Energy Regulator's Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("***Bulletin 21***") on July 8, 2016 and reaffirmed its position that an liability management rating of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and 2.0 remains the requirement for transferees. However, *Bulletin 21* did provide the Alberta Energy Regulator with additional flexibility to permit licensees to acquire additional Alberta Energy Regulator-licensed assets if:

1. The licensee already has an liability management rating of 2.0 or higher;
2. The acquisition will improve the licensee's liability management rating to 2.0 or higher; or
3. The licensee is able to satisfy its obligations, notwithstanding an liability management rating below 2.0, by other means.

The Alberta Energy Regulator provided no indication of what other means would be considered. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the Alberta Energy Regulator, despite a transferee's liability management rating not meeting the interim requirement. The Alberta Court of Appeal heard the appeal of the *Redwater* decision on October 11, 2016, with the Court reserving its decision.

The Alberta Energy Regulator implemented the Inactive Well Compliance Program to address the growing inventory of inactive wells in Alberta and to increase the Alberta Energy Regulator's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("***Directive 013***"). The Inactive Well Compliance Program applies to all inactive wells that are noncompliant with *Directive 013* as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the Inactive Well Compliance Program into compliance with the requirements of *Directive 013* within 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or by suspending the wells in accordance with *Directive 013* or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the Inactive Well Compliance Program is available on the Alberta Energy Regulator's Digital Data Submission system. The Alberta Energy Regulator has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the Inactive Well Compliance Program fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota.

Climate Change Regulation

Federal

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" which set forth a plan for regulations to address both greenhouse gas emissions 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 outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, 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.

As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC), 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; however, the greenhouse gas emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution to the UNFCCC. Intended Nationally Determined Contributions were communicated prior to the 2015 United Nations Climate Change Conference, held in Paris, France, which led to the Paris Agreement that came into force November 4, 2016. Among other items, the Paris Agreement constitutes the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The Government of Canada ratified the Paris Agreement on December 12, 2016, and pursuant to the agreement, Canada’s Intended Nationally Determined Contribution became its Nationally Determined Contributions. As a result, the Government of Canada replaced its Intended Nationally Determined Contribution of a 17% reduction target established in the Copenhagen Accord with a Nationally Determined Contributions of 30% reduction below 2005 levels by 2030.

On June 29, 2016, the North American Climate, Clean Energy and Environment Partnership was announced among Canada, Mexico and the United States, which announcement included an action plan for achieving a competitive, low-carbon and sustainable North American economy. The plan includes setting targets for clean power generation, committing to implement the Paris Agreement, setting out specific commitments to address certain short-lived climate pollutants, and the promotion of clean and efficient transportation.

Additionally, on December 9, 2016, the Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of $10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by $10 annually until it reaches $50 per tonne in 2022 at which time the program will be reviewed.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on our operations and cash flow.

Alberta

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 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 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* applies to facilities emitting more than 100,000 tonnes of greenhouse gas emissions in 2003 or any subsequent year ("**Regulated Emitters**"), 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*.

On June 25, 2015, the Government of Alberta renewed the *Specified Gas Emitters Regulation* for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. As of 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their 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, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

A Regulated Emitter can meet its emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments, and (5) by contributing to the Climate Change and Emissions Management Fund. Contributions to the Climate Change and Emissions Management Fund are made at a rate of $15 per tonne of greenhouse gas emissions, increasing to a rate of $20 per tonne of greenhouse gas emissions in 2016 and $30 per tonne of greenhouse gas emissions in 2017. Proceeds from the Climate Change and Emissions Management Fund are directed at testing and implementing new technologies for greening energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan. On June 7, 2016, the *Climate Leadership Implementation Act* was passed into law. The *Climate Leadership Implementation Act* enacted the *Climate Leadership Act* introducing a carbon tax on all sources of greenhouse gas emissions, subject to certain exemptions. An initial economy-wide levy of $20 per tonne was implemented on January 1, 2017, increasing to $30 per tonne in January of 2018. All fuel consumption—including gasoline and natural gas—will be subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Regulated Emitters will remain subject to the *Specified Gas Emitters Regulation* framework until the end of 2017 and are exempt from paying the carbon levy on fuels used in operations until this time. Upon the expiry of the *Specified Gas Emitters Regulation*, the Government of Alberta intends to transition to a proposed *Carbon Competitiveness Regulation*, in which sector specific output-based carbon allocations will be used to ensure competitiveness. A 100 megatonne per year limit for greenhouse gas emissions was implemented for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit.

There are certain exemptions to the carbon levy imposed by the *Climate Leadership Act*. Until 2023, fuels consumed, flared or vented in a production process by conventional oil and gas producers will be exempt from the carbon levy. An exemption also applies for biofuels and fuels sold for export. In addition, marked fuels used in farming operations as well as personal and band uses by First Nations are exempt.

The passing of the *Climate Leadership Implementation Act* is the first step towards executing the Climate Leadership Plan (other legislation is still pending). In addition to enacting the *Climate Leadership Act*, the *Climate Leadership Implementation Act* also enacted the *Energy Efficiency Alberta Act,* which enables the creation of Energy Efficiency Alberta, a new Crown corporation to support and promote energy efficiency programs and services for homes and businesses.

The Government of Alberta also signaled its intention through its Climate Leadership Plan to implement regulations that would lower methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage 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.

RISK FACTORS

An investment in our Common Shares is subject to various risks including those risks inherent to the industry in which we operate. If any of these risks occur, our production, revenues and financial condition could be materially harmed, with a resulting decrease in the market price of the Common Shares. As a result, the trading price of our Common Shares could decline, and you could lose all or part of your investment.

You should carefully consider the following risk factors, as well as the other information contained in this Annual Information Form and our other public filings before making an investment decision. If any of the risks described below materialize, our business, financial condition or results of operations could be materially and adversely affected. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect our business, financial condition or results of operations. Residents of the United States and other non residents of Canada should have additional regard to the risk factors under the heading "*Certain Risks for United States and Other Non-Resident Shareholders*".

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

Risks Relating to Our Business and Operations

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

Our operational results and financial condition is dependent on the prices received for our oil and natural gas production. Since June 30, 2014, oil and natural gas prices have declined substantially. Any further declines or a sustained period at current prices of oil and natural gas would have an adverse effect on the carrying value of our proved and probable reserves, net asset value, borrowing capacity, revenues, profitability and funds from operations and ultimately on our financial condition.

Prices for crude oil and natural gas fluctuate in response to changes in the supply of, and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond our control. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of the Organization of the Petroleum Exporting Countries ("**OPEC**"), the condition of the Canadian, United States, European and Asian economies, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the ability to secure adequate transportation for products, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by us are affected primarily in North America by supply and demand, weather conditions, industrial demand, prices of alternate sources of energy and developments related to the market for liquefied natural gas. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, could also have a significant impact on the price of oil and natural gas. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars. Oil prices are expected to remain volatile as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, OPEC's recent decisions pertaining to the oil production of OPEC member countries, and non-OPEC member countries' decisions on production levels, among other factors. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax and royalty changes that may be implemented by the new governments.

In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium oil and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions, refining demand, the availability and cost of diluents used to blend and transport product and the quality of the oil produced, all of which are beyond our control. The supply of Canadian crude oil with demand from the refinery complex and access to those markets through various transportation outlets is currently finely balanced and, therefore, very sensitive to pipeline and refinery outages, which contributes to this volatility.

The economics of producing from some wells may change as a result of lower commodity prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of our reserves. We might also elect not to produce from certain wells at lower prices. Volatile oil and natural gas prices also make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

A prolonged period of low and/or volatile commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due, it could also result in a delay or cancellation of existing or future drilling, development or construction programs, unutilized long-term transportation commitments and a reduction in the value and amount of our reserves.

We conduct assessments of the carrying value of our assets in accordance with International Financial Reporting Standards, as issued by the International Accounting Standards Board. If crude and natural gas forecast prices decline, it could result in downward revisions to the carrying value of our assets and our net earnings could be adversely affected.

If oil and natural gas prices remain at their current levels or decrease further, our estimates of total reserves and present values thereof may be reduced.

Our reserves as at December 31, 2016 are estimated using forecast pricing escalating prices as set forth under "*Description of Our Business – Disclosure of Reserves Data and Other Oil and Natural Gas Information – Forecast Prices and Costs* ". These prices are substantially above current oil and natural gas prices. If oil and gas prices stay at current levels or drop further our reserves may be reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel us to re-evaluate our development plans and reduce or eliminate various projects with marginal economics.

In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, our cash flow resulting in a reduced capital expenditure budget. As a result, we may not be able to replace our production with additional reserves and both our production and reserves could be reduced on a year over year basis.

The performance of the Little Bow ASP project will have a material impact on us

The Little Bow ASP project is one of our key assets. The performance of this asset will have a material impact on Zargon's financial performance over the coming years. Risk factors associated with our ASP project include the following, without limitation:

Production Risks

There is a risk that production and reserves relating to the existing scope of the Little Bow ASP project, and any future expansions or additions to the project will not meet forecasted oil production targets. Specific risk factors associated with the production and reserves relating to our ASP project include the following, without limitation:

- reduced oil recovery from injected chemical due to factors such as injectant performance, reservoir sweep efficiency, injectant/mineralogical interactions, thief zones, injectant degradation due to operating conditions;
- reduced injectivity and/or productivity due to pipeline or other equipment failures, loss of injection or production wells, limitations in installed equipment capacity;
- geological complexities or features in the oil reservoir unknown at the time of project implementation which affect the effectiveness of injectant in oil recovery;
- operational interruptions in Zargon's injection facility, oil processing battery, field pipelines etc. due to mechanical failure, weather related interruptions, seasonal access issues, maintenance and etc.; and
- operational interruptions due to interruptions in third party facilities and services such as pipelines, chemical suppliers, chemical transport systems and electrical power supply.

There is a risk that capital projects, undertaken to support the existing scope of the Little Bow ASP Project and future expansions or additions to the project will not be completed on time or on budget. Additionally, there is a risk that such projects may have delays, interruptions of operations or increased costs due to many factors, including, without limitation:

- inability to attract or retain sufficient numbers of qualified workers;
- construction performance falling below expected levels of output or efficiency;
- design errors;
- non-performance by, or financial failure of, third-party contractors;
- labour disputes, disruptions or declines in productivity;
- increases in materials or labour costs;
- conditions imposed by regulatory approvals;
- delays induced by weather;
- errors in construction;
- changes in project scope;
- unforeseen site surface or subsurface conditions;
- transportation or construction accidents including chemical spills or other environmental matters;
- permit requirement violation; and
- failure of existing wells, surface equipment, pipelines or other related facilities.

There is a risk that future capital costs for the chemical injectant utilized in the Little Bow ASP Project will be higher than forecast due to many factors, including without limitation:

- changes in foreign currency exchange rates;
- changes in vendor pricing;
- modifications to the project injection schedule and injection targets;
- changes in transportation charges; and
- interruptions in rail or other transport or logistical services.

Operating Costs

The operating costs of the project have the potential to vary considerably throughout the operating period and will be significant components of the cost of production of any petroleum products produced by the project. Project economics and our overall earnings may be reduced if increases in operating costs are incurred. Factors which could affect operating costs include, without limitation:

- the amount and cost of labour to operate the project;
- the cost of chemicals;
- the cost of electricity;
- power outages, particularly in winter when freeze-ups could occur;
- reliability of the facilities;
- the maintenance cost of the facilities;
- the cost of insurance; and
- catastrophic events such as fires, earthquakes, storms or explosions.

The market for heavy oil is more limited than for light and medium grades of oil, making it more susceptible to supply and demand fundamentals. Future price differentials are uncertain and any increase in heavy oil differentials could have an adverse effect on the anticipated returns from the project as well as our overall business, financial condition, results of operations and cash flows.

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

We deliver our products through gathering, processing and pipeline systems some of which we do not own. Access to the pipeline capacity for the transport of crude oil into the United States has become inadequate for the amount of Canadian production being exported to the United States and has recently resulted in significantly lower amounts being realized by Canadian producers compared with the WTI price for crude oil. 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. Although we currently do not directly transport oil by rail, we could be affected by both positive and negative impacts (i.e. pricing of our oil sales from supply/demand issues) that could result from significant fluctuations to this transport method. Material structural changes are required to reduce these bottlenecks and the resulting steep price discounts.

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. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect our production, operations and financial results. The federal government has signaled that it plans to review the National Energy Board approval process for large projects. This may cause the timeframe for project approvals to increase for current and future applications. There can be no assurance that such regulatory approvals will be secured on a timely basis or at all.

The lack of access to capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition.

A portion of our production may, from time to time, be processed through facilities owned by third parties and which we do not have control of. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuance or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale. Certain pipeline leaks have gained media and other stakeholder attention and may result in additional regulation or changes in law which could impede the conduct of our business or make our operations more expensive.

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. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

Our business is impacted by a number of factors, including volatility of prices for oil and natural gas, interest rates, sources of capital, changes in legislation and those set forth below

Our ability to add to our petroleum and natural gas reserves is highly dependent on our success in exploiting existing properties and acquiring additional reserves. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce petroleum and natural gas reserves. Future oil and natural gas exploration may involve unprofitable efforts, not only from unsuccessful wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completion (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion, operating and other costs. Drilling hazards or environmental damage could greatly increase the cost of operations (including hydraulic fracturing), and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. New wells we drill or participate in may not become productive and we may not recover all or any portion of our investment in wells we drill or participate in. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project.

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

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

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

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

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

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. Material increases in the value of the Canadian dollar related to the U.S. dollar will negatively affect our production revenue. Accordingly, Canadian/United States exchange rates could affect the future value of our as determined by our independent evaluator.

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

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.

Significant political events may cause uncertainty in financial and economic markets

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the recent presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of the North American Free Trade Agreement, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on our businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on our ability to market our products internationally, increase costs for goods and services required for our operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and the market value of its Common Shares.

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

Our exploration and production facilities and other operations and activities emit greenhouse gases which may require us to comply with greenhouse gas emissions legislation at the provincial or federal level. 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 UNFCCC and 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; however, these greenhouse gas emission reduction targets were not binding.

Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage greenhouse gas emissions. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented new greenhouse gas emission reduction targets of a 30% reduction from 2005 levels by 2030. In addition, the Government of Canada announced it would implement a Canada wide price on carbon to further reduce its greenhouse gas emissions. In addition, on January 1, 2017 the *Climate Leadership* Act came into effect in the Province of Alberta introducing a carbon tax on almost all sources of greenhouse gas emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. 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. 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.

In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of greenhouse gas and resulting requirements, it is not possible to predict the impact us and our operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

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

Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and gas industry operations. 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 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 will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements 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.

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

Amounts paid in respect of interest and principal on debt may reduce future capital expenditures. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service. Although we believe our current cash positions and cash flow from operations will be sufficient for our immediate requirements, there can be no assurance that the amount will be adequate for our future financial obligations including our future capital expenditure program, or that we will be able to obtain additional funds.

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

From time to time we may enter into transactions which may be financed in whole or in part with debt. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise. To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain or expand existing assets and reserves may be impaired, and our assets, liabilities, business, financial condition and results of operations. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

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

We believe that estimated funds from operations will be sufficient to substantially finance our current operations and planned capital expenditures for the ensuing year. The timing of most of our capital expenditures is discretionary and there are no material long-term capital expenditure commitments. However, if funds from operations are lower than expected or capital costs for these projects exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing properties, we may be required to seek additional capital to maintain our capital expenditures at planned levels. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties.

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

We may manage the risk associated with changes in commodity prices by entering into petroleum or natural gas price hedges. If we hedge our commodity price exposure, we may forego some of the benefits we would otherwise experience if commodity prices were to increase. As at December 31, 2016, our income statement reflected $4.1 million of unrealized losses resulting from hedges to protect our commodity risk exposure. For more information in relation to our commodity hedging program, see "*Description of our Business – Disclosure of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Gas Information – Forward Contracts*".

We may initiate certain hedges to attempt to mitigate the risk of the Canadian dollar appreciating against the U.S. dollar. An increase in the Canada/U.S. foreign exchange rate will impact future dividends and the future value of our reserves as determined by independent evaluators. These hedging activities could expose us to losses and to credit risk associated with counterparties with which we contract.

Our current hedging contracts provide a benefit to us during this period of low oil and natural gas prices by providing a floor price for a significant amount of production. This benefit will only be realized for the period and for the commodity quantities in those contracts. The benefits from such derivatives contracts will be realized by the end of December, 2017. Additional hedges might not be available at prices similar to our current hedge prices, which could adversely impact our revenues.

Our obligations under our hedging contracts are secured by a floating charge on our assets. If we fail to comply with the covenants in our hedging contracts, it could result in seizure and/or sale of our assets. We are also exposed to counterparty credit risk as a result of our hedging contracts.

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

We are exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, third party operators, marketers of our petroleum and natural gas production, hedge counterparties and other parties. We manage this credit risk by entering into sales contracts with creditworthy entities and reviewing our exposure to individual entities on a regular basis. However, in the event such parties fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, we may be unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

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

The oil and natural gas industry in Canada is subject to federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and sites (including restrictions on production) and possibly the expropriation or cancellation of contract rights. Governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas and such regulations may be amended from time to time. 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 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. See "*Industry Conditions*".

Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its obligation. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of our deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to our compliance requirements. In addition, the liability management system may prevent or interfere with our ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The recent Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re)* 2016 ABQB 278, found an operational conflict between the *Bankruptcy and Insolvency Act* and the Alberta Energy Regulator's abandonment and reclamation powers when the licensee is insolvent. The Alberta Energy Regulator appealed this decision and issued interim rules to administer the liability management program and until the Alberta Government can develop new regulatory measures to adequately address environmental liabilities. The decision from this appeal has not been released. There remains a great deal of uncertainty as to what new regulatory measures will be developed or what the impact of the court decision will have on other provinces. See "*Industry Conditions - Liability Management Rating Programs*".

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).

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

Due to the conditions in the oil and gas industry and/or global economic volatility, we may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. Continued depressed oil and natural gas prices have caused decreases, and may cause further decreases, in our cash flow. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to access sufficient capital for our capital expenditures and acquisitions could be impaired and, as a result, may have a material adverse effect on our ability to execute our business strategy and on our financial condition. There can be no assurance that financing will be available or sufficient to meet these requirements or for other corporate purposes or, if financing is available, that it will be on terms appropriate and acceptable to us. Should the lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued resulting in a dilutive effect on current and future Shareholders.

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

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

In general, estimates of economically recoverable petroleum and natural gas reserves and the future net revenues therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of petroleum and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are based on professional judgment and classifications of reserves, which, by their nature have a high degree of subjectivity. For those reasons, estimates of the economically recoverable petroleum and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary.

The reserves and recovery information contained in the McDaniel Report is only an estimate and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by McDaniel and such variations could be material. The McDaniel Report has been prepared using certain commodity price assumptions which are described in the notes to the reserves tables. If we realize lower prices for crude oil, NGLs and natural gas and they are substituted for the price assumptions utilized in the McDaniel Report, the present value of estimated future net revenues for our reserves and our net asset value would be reduced and the reduction could be significant. The estimates in the McDaniel Report are based, in part, on the timing and success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the McDaniel Report will be reduced, in future years, to the extent that such activities do not achieve the level of success assumed in the McDaniel Report.

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

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

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

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

There is 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 ensure a profit on the investment or recovery of drilling, completion and operating costs.

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

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

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

The continuing production from a property, and to some extent the marketing of production, is dependent upon the ability of the operators of our properties. Approximately 9.6 percent of our properties are operated by third parties, based on daily production. Our return on assets operated by others depends upon a number of factors that may be outside of our control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices. In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which we have an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations we may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, us potentially becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect our financial and operational results.

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

Delays in business operations could adversely affect the market price of the Common Shares

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

- restrictions imposed by lenders;

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

Any of these delays could expose us to additional third party credit risks.

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

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

We do not have a credit facility and any future credit facilities may not provide sufficient liquidity

We do not have a credit facility in place and any future credit facilities may not provide sufficient liquidity. There is no certainty that we will be able to obtain additional financing on economic terms attractive to us, if at all.

Hydraulic fracturing is subject to certain risks

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of natural gas and oil from reservoirs that were previously unproductive. We use hydraulic fracturing extensively in our operations. With the increase in the use of fracture stimulations in horizontal wells there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology as it relates to the environment. This increased attention to fracture stimulations may result in increased regulation or changes of law which may make the conduct of our business more expensive or prevent us from conducting our business as currently conducted. Any new laws, regulation or permitting requirements regarding hydraulic fracturing could lead to operational delays or increased operating costs, 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.

Changes in government regulations that affect the oil and natural gas industry could adversely affect us

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

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. See "*Industry Conditions*".

On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See "*Industry Conditions - Royalties and Incentives*".

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

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

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

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

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.

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

We make acquisitions and dispositions of businesses and assets in the ordinary course of our business. Achieving the benefits of acquisitions depends 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 our operations. The integration of acquired business 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. There is no assurance that we will be able to continue to complete acquisitions or dispositions of oil and natural gas properties which realize all the synergistic benefits.

We periodically dispose of non-core assets so that 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.

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

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

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

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

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

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

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. If we do implement such technologies, there is no assurance that we will do so successfully. 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.

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.

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

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

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

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

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or our ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the 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 effectively market the oil and natural gas that we produce effectively.

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

Our operations and expertise are currently primarily focused on oil and gas production and development in the Western Canadian Sedimentary Basin and the United States. In the future we may acquire 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.

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

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

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

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

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

Although title reviews are conducted prior to any purchase of significant resource assets, such reviews cannot guarantee that an unforeseen defect in the chain of title will not arise to defeat our title to certain assets. 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 that we control that, if successful or made into law, could impair our activities on them and result in a reduction in the amount of funds from operations, which could result in a lower market price of the Common Shares.

We are affected by seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access its properties and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for crude oil and natural gas.

Our permitted investments may be risky

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

A shortfall in the supply of diluent may increase our costs

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport heavy oil and bitumen to market and correspondingly increasing our overall operating cost, decreasing our net revenues and negatively impacting the overall profitability of our heavy oil and bitumen projects.

We may become involved in, named as a party to, or be the subject of, various legal proceedings

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.

In addition, due to the rapid development of oil and gas technology, 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 in which it is alleged that we have infringed the intellectual property rights of others or commence lawsuits against others who we believe are infringing upon our rights. Our involvement in intellectual property litigation could result in significant expense, adversely affecting the development of our assets or intellectual property or diverting the efforts of our technical and management personnel, whether or not such litigation is resolved in our favour. In the event of an adverse outcome as a defendant in any such litigation, we may, among other things, be required to: (a) pay substantial damages; cease the development, use, sale or importation of process that infringe upon other patented intellectual property; (b) expend significant resources to develop or acquire non-infringing intellectual property; (c) discontinue processes incorporating infringing technology; or (d) obtain licences to the infringing intellectual property. We may not be successful in such development or acquisition or that such licences would be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other/ resources and could have a material adverse effect on our business and financial results.

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.

We have become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure

We depend on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, we are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. We apply technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on our business, financial condition and results of operations.

Risks Relating to Ownership of Common Shares

Our Board of Directors has discretion in the payment of dividends

On November 11, 2015, as a result of volatile, uncertain and exceptionally low oil prices, we suspended our monthly dividend until further notice The amount of future cash dividends, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the *Business Corporations Act* (Alberta) for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of our Board of Directors and management team, we will change our dividend policy from time to time and, as a result, any future cash dividends could be reduced or suspended entirely. The future treatment of dividends for tax purposes will be subject to the nature and composition of our dividends and potential legislative and regulatory changes.

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

Certain Risks for United States and Other Non-Resident Shareholders

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

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

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

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

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

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

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

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 the Debenture Indenture, which has been filed on SEDAR at www.sedar.com.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

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

TRANSFER AGENT AND REGISTRAR

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 – Continuous Disclosure Obligations by us during, or related to, our most recently completed financial year other than McDaniel, our independent engineering evaluator, and Ernst & Young LLP, our auditors.

None of the "designated professionals" (as that term is defined in National Instrument 51-102) of McDaniel had any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the report, valuation, statement or opinion prepared by it, at any time thereafter or to be received by them.

Ernst & Young LLP is independent in accordance with the Rules of Professional Conduct as outlined by the Chartered Professional Accountants of Alberta.

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

ADDITIONAL INFORMATION

Additional information relating to us can be found on SEDAR at www.sedar.com and on our website at www.zargon.ca. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans are contained in our information circular – proxy statement dated April 17, 2017 relating to our annual and special Shareholders meeting to be held on May 30, 2017. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2016 and the related management's discussion and analysis.

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

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

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

(Form 51-101F3)

Management of Zargon Oil & Gas Ltd. ("**Zargon**") is responsible for the preparation and disclosure of information with respect to Zargon's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

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

The Audit and Reserves Committee of the board of directors of Zargon has

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

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

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

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

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data or prospective resources 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) C.H. Hansen
President and Chief Executive Officer

(signed) C.M. Hustad
Vice President, Development

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

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

February 23, 2017

APPENDIX B

REPORT ON RESERVES DATA BY MCDANIEL

(Form 51-101F2)

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

1. We have evaluated Zargon's reserves data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. 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.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Zargon evaluated for the year ended December 31, 2016, and identifies the respective portions thereof that we have evaluated and reported on to Zargon's board of directors:

Independent Qualified Reserves Evaluator or Auditor	**Effective Date of Evaluation Report**	**Location of Reserves**	**Net Present Value of Future Net Revenue (thousands before income taxes, 10% discount rate)**			
			Audited	**Evaluated**	**Reviewed**	**Total**
McDaniel & Associates Consultants Ltd.	December 31, 2016	Canada	$nil	$106,094	$nil	$106,094
		United States	$nil	$26,182	$nil	$26,182

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our reports.

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

Executed as to our report referred to above:

(signed) McDaniel & Associates Consultants Ltd.
Calgary, Alberta, Canada

February 23, 2017

APPENDIX C

MANDATE & TERMS OF REFERENCE OF THE AUDIT AND RESERVES COMMITTEE

Role and Objective

The Audit and Reserves Committee (the "**Committee**") is appointed by the Board of Directors (the "**Board**") of Zargon Oil & Gas Ltd. ("**Zargon**" or the "**Corporation**"), to which the Board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements, the audited financial statements and other mandatory disclosure releases containing financial information, and reviewing the annual independent report of the Corporation's petroleum and natural gas reserves and recommending all, for board of director approval.

Membership of Committee

1. The Committee shall be comprised of at least three (3) directors of Zargon, none of whom are members of management of Zargon and all of whom are "independent" (as such term is used in Multilateral Instrument 52-110 - *Audit Committees* ("**MI 52-110**") and National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**"). Committee members shall also meet the independence requirements of the regulatory bodies to which the Corporation may be subject to.

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

3. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.

Mandate and Responsibilities of Committee

1. The Committee shall, in addition to any other duties and responsibilities specifically delegated to it by the Board, generally assume responsibility for developing the approach of the Corporation to matters concerning all financial information and disclosure and all petroleum and natural gas reserves information and disclosure and, from time to time, shall review and make recommendations to the Board as to such matters. Specifically, the Committee will have the authority and responsibility for:

    (a) Audit Matters:

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

    (ii) To provide better communication between directors and external auditors;

    (iii) To enhance the external auditor's independence;

    (iv) To increase the credibility and objectivity of financial reports;

    (v) To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors;

    (vi) 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;

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

A. Identifying, monitoring and mitigating business risks; and

B. Ensuring compliance with legal, ethical and regulatory requirements.

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

A. Reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

B. Reviewing significant accruals, reserves or other estimates such as the impairment test calculation;

C. Reviewing accounting treatment of unusual or non-recurring transactions;

D. Ascertaining compliance with covenants under loan agreements;

E. Reviewing disclosure requirements for commitments and contingencies;

F. Reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

G. Reviewing unresolved differences between management and the external auditors; and

H. Obtain explanations of significant variances with comparative reporting periods.

(ix) The Committee is to review the financial statements, prospectuses, management discussion and analysis ("**MD&A**"), annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information before release and prior to board approval. The Committee must be satisfied that adequate procedures are in place for the review of Zargon's disclosure of all other financial information and shall periodically access the accuracy of those procedures.

(x) With respect to the appointment of external auditors by the board, the Committee shall:

A. Recommend to the board the appointment of the external auditors;

B. 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;

C. When there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

D. 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.

(xi) Review with external auditors (and internal auditor if one is appointed by Zargon) their assessment of the internal controls of Zargon, their written reports containing recommendations for improvement, and management’s response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Zargon and its subsidiaries.

(xii) The Committee must pre–approve all non–audit services to be provided to Zargon or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre–approve non–audit services, provided that the member report to the Committee at the next scheduled meeting such pre–approval and the member comply with such other procedures as may be established by the Committee from time to time.

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

(xiv) The Committee shall establish a procedure for:

A. The receipt, retention and treatment of complaints received by Zargon regarding accounting, internal accounting controls or auditing matters; and

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

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

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

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

(b) Reserves Matters:

(i) In conjunction with the Corporation's senior engineering management, meet with the independent evaluating engineers being considered for appointment to review their qualifications and independence to ensure the independent evaluating engineers being considered for appointment are technically qualified and competent, are independent of management and to establish the terms of their engagement;

(ii) After consultation with the Corporation's senior engineering management recommend to the Board the appointment of the independent evaluating engineers to assist the Corporation in the annual review of its petroleum and natural gas reserves;

(iii) In consultation with the Corporation's senior engineering management determine the scope of the annual review of the petroleum and natural gas reserves by the independent evaluating engineers, having regard to regulatory reporting requirements;

(iv) Review both the procedures for providing petroleum and natural gas reserves information to the independent evaluating engineers and the information used by the independent evaluating engineers to enable the independent evaluating engineers to provide a report that will meet regulatory reporting requirements;

(v) In consultation with the Corporation's senior engineering management and the independent evaluating engineers:

A. Determine whether any restrictions affect the ability of the independent evaluating engineers to report on reserves data without reservations; and

B. Review the reserves data and the report of the independent evaluating engineers.

(vi) Recommend to the Board for filing, the report from the independent evaluating engineers and/or senior engineering management on the Corporation's petroleum and natural gas reserves data;

(vii) Ensure the disclosure to the public on the Corporation's petroleum and natural gas reserves is in compliance with regulatory requirements;

(viii) Review any proposals to change the independent evaluating engineers and/or resolve any differences between the independent evaluating engineers and management;

(ix) Meet on an annual basis with the Corporation's senior engineering management and/or the independent evaluating engineers of the Corporation to review and consider the evaluation of the Corporation's petroleum and natural gas reserves;

(x) Meet separately with the independent evaluating engineers and/or senior engineering management when the Committee deems it desirable and advise the Board on the results of such meeting; and

(xi) Co-ordinate meetings with the Corporation's senior engineering management, independent evaluating engineers and auditors as required to address matters of mutual concern in respect of the Corporation's evaluation of petroleum and natural gas reserves.

Meeting and Administrative Matters

1. Meetings of the Committee should be scheduled to take place at least four (4) times per year. Special meetings may be convened as required upon the request of the Committee Chairman or the CEO. The President and Chief Executive Officer and the Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman

2. A majority of the members of the Committee shall constitute a quorum. No business may be transacted by the Committee except at a meeting of its members at which a quorum of the Committee is present or by a resolution in writing signed by all the members of the Committee. Meetings may occur via telephone or teleconference

3. Any members of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board of Directors may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of shareholders following appointment as a member of the Committee

4. The Committee may invite such officers, directors and employees of the Corporation as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee

5. The time at which and place where the meetings of the Committee shall be held and the calling of meetings and the procedure in all respects at such meetings shall be determined by the Committee, unless otherwise determined by the by-laws of the Corporation or by resolution of the Board

6. Unless otherwise designated by the Board, the members of the Committee shall elect a Chairman from among the members and the Chairman shall preside at all meetings of the Committee. The Chairman of the Committee shall have a second and deciding vote in the event of a tie. In the absence of the Chairman, the members of the Committee shall appoint one of their members to act as Chairman. Notwithstanding the foregoing, in all circumstances the Chairman must be an outside director, unrelated to the Corporation

7. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board

8. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings

9. The Committee may obtain information from any employee of the Corporation and the Corporation's agents that it may require to carry out this mandate. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation, as determined by the Committee

10. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair

11. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the yearend financial statements) and at such other times as the external auditor and the Committee consider appropriate

12. Review annually the Committee mandate and terms of reference and recommend any changes to the Board