PRAIRIESKY
ROYALTY LTD

TSX: PSK

ANNUAL INFORMATION FORM / February 26, 2018

HIGH MARGINS ZERO CAPITAL

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ADVISORIES

Cautionary Statement Regarding Forward-Looking Information and Statements

This Annual Information Form (*AIF*) contains forward-looking information and statements (collectively, *forward-looking statements*). These forward-looking statements, which relate to future events or future performance, are provided to allow readers to better understand PrairieSky Royalty Ltd.'s (*PrairieSky* or the *Company*) business and prospects and may not be suitable for other purposes. 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, plan, continue, estimate, expect, may, will, project, predict, potential, targeting, intend, could, might, should, believe and similar expressions (including the negatives thereof). Forward-looking statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes the expectations reflected in the forward-looking statements included in this AIF are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These forward-looking statements speak only as of the date of this AIF. The Company assumes no obligation to revise or update these forward-looking statements except as required pursuant to applicable securities laws.

In particular, this AIF contains forward-looking statements pertaining to the following:

- the Company's objective to generate free cash flow and growth for its shareholders at a relatively low risk and low cost to the Company, and the proposed manner of achieving this objective;

- the Company's strategy with respect to future acquisitions;

- the Company's dividend policy, the funding of such dividends, the amounts expected to be paid under that policy in the future and the anticipated timing of payment of such dividends;

- the Company's business and growth strategy and the expectation that the Company will be successful in strategically seeking additional crude oil and natural gas royalty assets that provide the Company with medium-term to long-term value enhancement potential;

- the expectation that the Company will be able to successfully encourage third parties to actively develop the Royalty Properties (as defined herein) and the anticipation that only a small percentage of the Company's undeveloped land holdings will expire within one year;

- the expectation that the Company will secure additional leasing and royalty arrangements with operators and lessees on the Royalty Properties;

- the estimated volumes and future net revenues related to the Company's crude oil, natural gas and NGL (as defined herein) reserves and expectations regarding the ability of the Company to add to reserves through third party development activities and acquisitions undertaken by the Company;

- projected crude oil and natural gas production levels and certain costs and expenses associated with the Royalty Properties;

- the Company's belief that there will be minimal or no operating costs, capital costs, environmental liabilities or reclamation obligations incurred by the Company with crude oil and natural gas development on the Royalty Properties;

- the performance and characteristics of the Royalty Properties, including additional upside potential of many of the Royalty Properties;
- the timing and amount of capital expenditure programs and well drilling activity by third parties on the Royalty Properties;
- the expectation of not receiving any future royalty revenue from its royalty interest in the third party operated Highvale coal mine;
- anticipated future crude oil, natural gas and NGL prices and currency, exchange and interest rates;
- supply and demand for crude oil and natural gas;
- the primary sources of costs to the Company;
- the taxability of the Company; and
- treatment under governmental regulatory regimes, environmental legislation and tax laws.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this AIF:

- the Royalty Properties will not be developed by third parties in the manner anticipated by the Company;
- non-compliance with lease terms or payment or delivery delinquencies in respect of the Royalty Properties, including the credit risk associated with such third parties;
- volatility in the demand, supply and market prices for crude oil, natural gas and NGL;
- volatility in exchange rates;
- long-term reliance on third parties as lessees on the Fee Lands (as defined herein) and the operators and working interest owners on the Royalty Properties;
- risks and liabilities inherent in crude oil and natural gas operations;
- uncertainties associated with estimating crude oil, natural gas and NGL reserves and future production levels;
- increased costs incurred by the Company or the lessees on the Fee Lands and the operators and working interest owners on the Royalty Properties;
- competition for, among other things, third party capital and acquisitions of reserves, additional crude oil and natural gas assets and undeveloped lands;
- incorrect assessments of the value of acquisitions;
- risks related to the environment and changing environmental laws in relation to the operations conducted on the Royalty Properties;

- geological, technical, drilling and completions, processing and handling issues (including deductions from PrairieSky's royalty share of production) associated with crude oil and natural gas development activities by third parties;
- claims made or legal actions brought or realized against the Company or its properties or assets;
- a failure by the Company to hire or retain key personnel;
- breaches or failure of information systems and security (including risks associated with cyber-attacks);
- a decrease or elimination of the payment of dividends by the Company as a result of a Board (as defined herein) determination or restrictions under applicable agreements or corporate laws;
- general economic, market and business conditions;
- changes in tax or environmental laws or royalty or incentive programs relating to the oil and natural gas industry; and
- the other factors discussed under "*Risk Factors*" herein.

Forward-looking statements are based on a number of factors and assumptions that have been used to develop such statements but which may prove to be incorrect. Although PrairieSky believes that the assumptions underlying such forward-looking statements are reasonable, it can give no assurance that the plans, intentions or expectations upon which such forward-looking statements are based will occur. In addition to other factors and assumptions that may be identified in this AIF, assumptions have been made regarding, among other things:

- the ability of the lessees on the Fee Lands and the operators and working interest owners on the Royalty Properties to maintain or increase production and reserves from these properties;
- the ability and willingness of the lessees on the Fee Lands and working interest owners on the Royalty Properties to comply with, and the Company to enforce, lease terms and contractual provisions, as applicable, in order to receive payments in respect of the Royalty Properties;
- the ability of the lessees on the Fee Lands or the operators and working interest owners on the Royalty Properties to operate in a safe, efficient and effective manner;
- the timely receipt of any required regulatory approvals by lessees on the Fee Lands or the operators and working interest owners on the Royalty Properties;
- the willingness and financial capability of the lessees on the Fee Lands and working interest owners on the GORR Lands (as defined herein) to continue to develop and invest additional capital in the Royalty Properties;
- the ability of the lessees on the Fee Lands and working interest owners on the Royalty Properties to obtain financing on acceptable terms to fund exploration and development capital expenditures;
- field production rates, decline rates and the well performance and characteristics of the Royalty Properties;
- the ability to replace and increase crude oil, natural gas and NGL reserves and production associated with the Royalty Properties through third party development and acquisitions;

- the timing, cost and ability of third parties to access, maintain or expand necessary facilities and/or secure adequate product transportation and storage;
- the ability of the operators of the properties in which the Company has a royalty interest in, to successfully market their respective crude oil and natural gas products or, for royalty payments taken-in-kind by the Company, if any, the ability of the Company or a third-party marketer to successfully market the Company's in-kind crude oil and natural gas products;
- surface rights access being granted to third parties on the Royalty Properties;
- the ability of the Company to obtain and retain qualified staff, equipment and services in a timely and cost-efficient manner;
- the absence of any material litigation or claims against the Company;
- the general stability of the economic and political environment and the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Company has an interest in crude oil and natural gas properties; and
- future crude oil, natural gas and NGL prices and currency, exchange and interest rates.

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 AIF are expressly qualified by this cautionary statement.

Conversion of Natural Gas to Barrels of Oil Equivalent

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (*boe*). PrairieSky uses the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio based on the current price of crude oil to natural gas is significantly different from the 6:1 energy equivalency ratio, using a conversion ratio on a 6:1 basis may be misleading as an indication of value.

Presentation of Oil and Natural Gas Reserves and Production Information

All crude oil, natural gas and NGL reserves and other information with respect to the Royalty Properties in this AIF have been prepared and are presented in accordance with NI 51-101 (as defined herein). See "*Reserves and Other Oil and Gas Information — Notes and Definitions*" for additional information.

All acreage information with respect to the Fee Lands, GRT Lands (as defined herein) and GORR Lands in this AIF has been presented on a gross acre basis. For the Fee Lands, gross acres refer to the total percentage undivided interest acres in which the Company holds fee simple mineral title and the associated mines and minerals rights. For the GRT Lands and GORR Lands, gross acres refer to the total acres related to the leasehold or title interests held by a third party in the lands on which the Company holds the GRT Interests or GORR Interests (each as defined herein). Gross acres for the GRT Lands or GORR Lands do not account for the Company's net GRT Interests or GORR Interests percentage royalty ownership interest held in lands. Gross acreage for Crown Interest Lands (as defined herein) is the acres covered by the lease and the net acres are the Company's working interest share of the gross acres. The presentation of gross acres for the Fee Lands, GRT Lands and GORR Lands is consistent with the presentation by certain of the Company's peers that hold a royalty interest on lands leased to or by third parties.

All references in this AIF to "working interest" means the right granted to a lessee of a property to explore for and produce petroleum and/or natural gas on the leased lands, upon which such lessee bears the operating costs, capital costs, environmental liabilities or reclamation obligations associated with oil and natural gas development.

GLOSSARY OF TERMS

In this AIF, unless otherwise indicated or the context otherwise requires, the following terms shall have the indicated meanings. Certain other terms used in this AIF but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101. For additional definitions relating to oil and gas information, see "*Reserves and Other Oil and Gas Information — Notes and Definitions*". Words importing the singular include the plural and vice versa and words importing any gender include all genders. A reference to an agreement means the agreement as it may be amended, supplemented or restated from time to time.

ABCA means the *Business Corporations Act* (Alberta) and the regulations thereunder, as amended from time to time;

affiliate or *associate* has the meaning ascribed thereto in the *Securities Act* (Alberta), as amended from time to time;

Board means the board of directors of the Company as it may be comprised from time to time;

CNRL means Canadian Natural Resources Limited;

CNRL Assets means the: (i) unleased Fee Lands; (ii) leased Fee Lands; and (iii) contractual royalties (including GORR Interests and GRT Interests) acquired pursuant to the CNRL Purchase and Sale Agreement;

CNRL Parties means collectively, CNRL, Canadian Natural Resources, Canadian Natural Resources Northern Alberta Partnership and CNR Royalty Partnership;

CNRL Purchase and Sale Agreement means the royalty assets purchase and sale agreement dated November 8, 2015, entered into between the CNRL Parties and the Company, as amended, pursuant to which the Company completed the CNRL Royalty Acquisition;

CNRL Royalty Acquisition means the acquisition by the Company from the CNRL Parties of the CNRL Assets;

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook;

Common Shares means the common shares in the capital of the Company;

Crown Interest Lands means certain lands in which the Company holds or has acquired a lessee interest in a petroleum and/or natural gas lease or license, as more particularly detailed throughout this AIF, which are undeveloped with no wells, tangibles or other similar liability, and which the Company intends to sell or otherwise exchange for consideration of a GORR Interest;

crude oil means light oil, medium oil and heavy oil, tight oil and bitumen, collectively.

December 2015 Private Placement means the private placement of an aggregate of 26,976,000 Subscription Receipts at a price of $25.20 per Subscription Receipt for aggregate gross proceeds of $679,795,200 completed on December 2, 2015;

December 2016 Offering means the bought deal treasury offering, pursuant to a short form prospectus, of 9,200,000 Common Shares (including 1,200,000 Common Shares issued pursuant to the exercise in full of the over-allotment option) at a price of $31.40 per Common Share for aggregate gross proceeds of approximately $288.9 million completed January 6, 2017;

Encana means Encana Corporation;

Encana Purchase and Sale Agreement means the royalty business purchase and sale agreement dated May 22, 2014, entered into between Encana and the Company, pursuant to which the Company completed the Encana Royalty Acquisition;

Encana Royalty Acquisition means the acquisition by the Company from Encana of: (i) fee simple mineral title in lands prospective for petroleum, natural gas, NGL and certain other mineral rights located predominantly in central and southern Alberta; (ii) lessor interests in and to leases issued in respect of certain Fee Lands; (iii) royalty interests, including overriding royalty interests, gross overriding royalty interests and production payments on lands located predominantly in Alberta; (iv) the Seismic License; and (v) certain other related assets as set forth in the Encana Purchase and Sale Agreement;

Fee Lands means lands prospective for petroleum, natural gas and certain other mines and minerals in which the Company holds a fee simple interest as more particularly detailed throughout this AIF;

Freehold Mineral Tax means an annual tax levied by the Government of Alberta on the value of crude oil and natural gas production from non-government owned lands within Alberta;

GLJ means GLJ Petroleum Consultants Ltd., independent qualified reserves evaluators;

GLJ Price Forecast means the GLJ commodity price forecast as of January 1, 2018;

GLJ Report means the independent engineering evaluation of the crude oil, natural gas and NGL reserves relating to the Royalty Properties, prepared by GLJ with an effective date of December 31, 2017, and a preparation date of January 23, 2018;

GORR Interests means royalty and similar non-working interests (other than GRT Interests and Lessor Interests), including overriding royalty interests, gross overriding royalty interests, net profit interests and production payments on lands;

GORR Lands means certain lands in respect of which the Company holds GORR Interests as more particularly detailed throughout this AIF;

gross means: (i) in relation to the Company's interest in production or reserves, its working interest (operating or non-operating) share, if any, before deduction of royalties and without including any royalty interest of the Company; (ii) in relation to wells, the total number of wells in which the Company has an interest; and (iii) in relation to properties, the total area in which the Company has an interest;

GRT Interests means a trust or series of trusts settled by indenture or agreement which hold and collect, for the benefit of its unitholders, mineral interests and/or royalty payments in the form of lessor royalties;

GRT Lands means certain lands in which the Company holds GRT Interests as more particularly detailed throughout this AIF;

hydrocarbons means a solid, liquid or gas made up of compounds of carbon and hydrogen in varying proportions;

IPO means the initial public offering of the Company, pursuant to a secondary offering by Encana, completed on May 29, 2014, and resulting in the distribution by Encana of 52,000,000 Common Shares to the public, plus an additional 7,800,000 Common Shares on June 3, 2014, pursuant to the exercise of the over-allotment option granted by Encana to the underwriters of such offering;

Lessor Interests means lessor interests in and to leases that are currently issued in respect of certain Fee Lands;

Lindbergh Project means Pengrowth's SAGD thermal oil project, which is located in the Cold Lake area of Alberta, including Pengrowth's Muriel Lake properties;

net means: (i) in relation to the Company's interest in production or reserves, its Lessor Interests, GRT Interests, GORR Interests in production or reserves, after deduction of royalty obligations payable to other parties, if any; (ii) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's Lessor Interest, GRT Interest or GORR Interest in each of its gross wells; and (iii) in relation to the Company's working interest in a property, the total acreage in which the Company has a working interest multiplied by the working interest owned by the Company;

NGL means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons;

NI 51-101 means National Instrument 51-101 — *Standards of Disclosure for Oil and Gas Activities*;

Pengrowth means Pengrowth Energy Corporation;

Pengrowth GORR Acquisition means the acquisition of a 4% overriding royalty on current and future phases of the Lindbergh Project as well as seismic over certain lands in British Columbia and Alberta for an aggregate purchase price of $250 million;

person means and includes individuals, companies, corporations, limited partnerships, general partnerships, joint stock companies, limited liability companies, joint ventures, associations, trusts, banks, trust companies, pension funds, and other organizations, whether or not legal entities, and governments and agencies and political subdivisions thereof;

petroleum means a naturally occurring mixture consisting predominantly of hydrocarbons in the gaseous, liquid or solid phase, and as referenced in this AIF, includes crude oil and NGL;

Range GP means Range Royalty Management Ltd.;

Range Royalty means Range Royalty Limited Partnership;

Range Royalty Acquisition means the acquisition of all the issued and outstanding units of Range Royalty and all the issued and outstanding shares of Range GP by the Company effective December 19, 2014;

Reorganization means the internal reorganization involving Encana and the Company completed effective December 13, 2013, and the consolidation of Common Shares effective January 31, 2014;

Royalty Properties means collectively, the Fee Lands, the GORR Lands and the GRT Lands;

SAGD means steam assisted gravity drainage;

SEDAR means the System for Electronic Document Analysis and Retrieval;

Seismic Licence means the irrevocable, perpetual, royalty-free, non-exclusive licence to certain proprietary seismic data of Encana, granted to the Company by Encana as part of the Encana Royalty Acquisition and pursuant to the Seismic Licence Agreement;

Seismic Licence Agreement means the agreement dated May 27, 2014, entered into between Encana and the Company, pursuant to which Encana granted the Seismic Licence to the Company;

September 2014 Secondary Offering means the secondary offering by Encana, pursuant to a short form prospectus of the Company, completed on September 26, 2014, and resulting in the distribution by Encana of 72,000,000 Common Shares to the public;

shareholder means a holder of Common Shares;

Subscription Receipts means the subscription receipts of the Company issued pursuant to the December 2015 Private Placement with each subscription receipt entitling the holder thereof to receive, without payment of additional consideration or further action on the part of such holder, one Common Share upon the satisfaction of certain conditions, including that all material conditions to the completion of the CNRL Royalty Acquisition had been satisfied or waived (other than the payment of the purchase price for the CNRL Assets);

subsidiary has the meaning ascribed thereto in the ABCA;

Tax Act means the *Income Tax Act* (Canada) and the regulations thereunder, as amended from time to time; and

TSX means the Toronto Stock Exchange.

ABBREVIATIONS AND CONVERSIONS

In this AIF, the following abbreviations have the meanings set forth below consistent with Appendix B of the COGE Handbook, where applicable:

API	American Petroleum Institute
bbl	barrel
bbl/d	barrels per day
Bcf	billion cubic feet
boe	barrel of oil equivalent
boe/d	barrels of oil equivalent per day
Mbbl	thousands of barrels
Mbbl/d	thousands of barrels per day
Mboe	thousands of barrels of oil equivalent
Mboe/d	thousands of barrels of oil equivalent per day
Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
Mcfe	thousand cubic feet equivalent
MMboe	million barrels of oil equivalent
MMbtu	million British thermal units
MMcf	million cubic feet
MMcfpd	million cubic feet per day
M$	thousands of dollars

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units) consistent with Appendix C of the COGE Handbook:

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbl	cubic metres	0.159
cubic metres	bbl	6.292
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

CORPORATE STRUCTURE

General

The Company was incorporated under the ABCA under the name "1786071 Alberta Ltd." on November 27, 2013. In December 2013 and January 2014, the Company undertook the Reorganization. On April 11, 2014, the Company changed its name to "PrairieSky Royalty Ltd." Prior to the completion of the IPO, the Company was a wholly-owned subsidiary of Encana.

On May 29, 2014, the Company completed the IPO, pursuant to which Encana distributed 52,000,000 Common Shares to the public at a price of $28.00 per Common Share. On June 3, 2014, the over-allotment option granted to the underwriters of the IPO was exercised in full and an additional 7,800,000 Common Shares were sold by Encana at a price of $28.00 per Common Share, bringing the aggregate gross proceeds to Encana from the IPO to approximately $1.67 billion. On September 26, 2014, the Company completed the September 2014 Secondary Offering, pursuant to which Encana distributed 70,200,000 Common Shares to the public at a price of $36.50 per Common Share for aggregate gross proceeds to Encana of $2.6 billion. Following the September 2014 Secondary Offering, Encana no longer held any Common Shares.

On December 19, 2014, the Company acquired all of the issued and outstanding units of Range Royalty and all of the outstanding shares of Range GP in exchange for the issuance of approximately 19.3 million Common Shares. As part of the Range Royalty Acquisition and through a series of transactions: (i) Range Royalty was wound up and distributed its assets to PrairieSky; and (ii) PrairieSky amalgamated with Range GP and continued under the name "PrairieSky Royalty Ltd." PrairieSky is the legal successor in interest to Range Royalty and Range GP. On November 8, 2017, PrairieSky amalgamated with its wholly-owned subsidiary, 2079323 Alberta Ltd., an immaterial subsidiary established for the sole purpose of acquiring certain royalty interests in Saskatchewan. PrairieSky is the legal successor in interest following this amalgamation.

As of December 31, 2017, and the date hereof, PrairieSky has no material subsidiaries.

The issued and outstanding Common Shares are listed and posted for trading on the TSX under the trading symbol "PSK".

GENERAL DEVELOPMENT OF THE BUSINESS

The following is a summary description of the development of PrairieSky's business for the three most recently completed financial years.

Year Ended December 31, 2017

The Pengrowth GORR Acquisition

On December 14, 2016, the Company entered into a definitive agreement to acquire a 4% gross overriding royalty on current and future phases of the Lindbergh Project as well as seismic over certain lands in British Columbia and Alberta for an aggregate purchase price of $250 million, which was financed through the December 2016 Offering. The Pengrowth GORR Acquisition was completed on January 6, 2017 with an effective date of January 1, 2017.

The December 2016 Offering

On December 14, 2016, the Company entered into an agreement in respect of a bought deal treasury offering of 9,200,000 Common Shares (including 1,200,000 Common Shares issued pursuant to the exercise of the over-allotment option) at a price of $31.40 per Common Share for aggregate gross proceeds of approximately $289 million. The December 2016 Offering was completed on January 6, 2017 and a portion of the proceeds therefrom were used to fund the purchase price of the Pengrowth GORR Acquisition.

Year Ended December 31, 2016

The Q4 2016 Royalty Acquisitions

On December 1, 2016, the Company announced that it had completed four separate acquisition transactions for aggregate consideration of $117.3 million, including over 100,000 acres of Fee Lands. In the two largest transactions, PrairieSky acquired a combined 3.95% royalty interest at Onion Lake, Saskatchewan. The Onion Lake royalty interest provides exposure to a long life heavy and thermal oil project, including future phases. The royalty acquisitions were funded entirely from available cash on hand.

Year Ended December 31, 2015

The July 2015 Offering

On July 7, 2015, the Company completed a bought deal treasury offering of 6,336,000 Common Shares (including 576,000 Common Shares issued pursuant to the exercise in full of the over-allotment option) at a price of $31.25 per Common Share for aggregate gross proceeds of $198 million.

The December 2015 Private Placement

On December 2, 2015, the Company completed a private placement of 26,976,000 Subscription Receipts at a price of $25.20 per Subscription Receipt for aggregate gross proceeds of $679,795,200. The Common Shares underlying the Subscription Receipts were issued on December 16, 2015, in connection with the completion of the CNRL Royalty Acquisition and the gross proceeds of the December 2015 Private Placement were used to fund substantially all of the cash consideration for the CNRL Royalty Acquisition. PrairieSky obtained a receipt for a final short form prospectus qualifying the distribution of such Common Shares on December 9, 2015.

The CNRL Royalty Acquisition

On December 16, 2015, PrairieSky completed the CNRL Royalty Acquisition pursuant to which it acquired the CNRL Parties' entire interest as a fee simple mineral title owner, lessor, gross overriding royalty and owner of other similar non-working interests in the CNRL Assets for a purchase price of $1.8 billion (prior to customary closing adjustments) payable with cash consideration of $680 million and the issuance to the CNRL Parties of 44,444,444 Common Shares at a deemed price of $25.20 per share. Substantially all of the cash consideration was funded by the December 2015 Private Placement. The CNRL Royalty Acquisition had an effective date of October 1, 2015.

The CNRL Assets were comprised of over 5.0 million acres of Royalty Properties which span several established oil and gas production areas within the Western Canadian Sedimentary Basin.

Pursuant to the terms of the CNRL Purchase and Sale Agreement, on June 6, 2016 the CNRL Parties distributed 21,806,967 Common Shares to the shareholders of CNRL. After such distribution, the CNRL Parties collectively owned less than 10% of the issued and outstanding Common Shares.

Significant Acquisitions

The Company did not complete any acquisitions that would be considered significant pursuant to National Instrument 51-102 – *Continuous Disclosure Obligations* during the year ended December 31, 2017.

BUSINESS OF THE COMPANY

General

The Company currently has one of the largest independently-owned portfolios of fee simple mineral title and oil and gas royalty interests in Canada. The Company is focused on encouraging third parties to actively develop the Royalty Properties while strategically seeking additional crude oil and natural gas royalty assets that provide the Company with medium-term to long-term value enhancement potential, including the acquisition of lands at Crown land sales for purposes of complementing the Company's fee title land base and pursuing prospective farmout strategies. The Company does not directly conduct operations to explore for, develop or produce petroleum or natural gas; rather, third party development of the Royalty Properties provides the Company with royalty revenues as petroleum, natural gas and associated substances are produced from such properties. The Company's costs are primarily production and mineral taxes, administrative expenses and corporate income taxes. Costs typically related to upstream drilling, equipment, production and asset retirement obligations are not incurred by the Company; instead, these costs are incurred by third parties who conduct activities on the Royalty Properties.

The Company's objective is to generate free cash flow and growth for its shareholders through indirect oil and gas investment at a relatively low risk and low cost to the Company. The Company strives to achieve this objective by: (i) focusing on organic growth of its royalty revenue from the Royalty Properties; (ii) proactively monitoring and managing its portfolio of Royalty Properties; (iii) generating efficiencies in its business and administration thereof, with a focus on managing controllable costs; and (iv) selectively pursuing strategic business development opportunities that are relatively low risk to the Company and accretive to shareholders.

The Company's revenue stream is derived predominantly from royalties payable by lessees and working interest owners from oil and natural gas production on the Royalty Properties and revenues derived from related activities, including lease issuance bonus consideration and lease rentals. The Company actively pursues additional leasing and royalty arrangements with operators and lessees on the Royalty Properties and seeks to, from time to time, expand its portfolio of royalty interests.

Overview of Royalties

Royalty ownership differs significantly from a working interest position. A working interest owner is responsible for its share of operating costs, capital costs, environmental liabilities and reclamation obligations, usually in proportion to its ownership percentage, and it receives its *pro rata* share of revenue. A royalty holder enjoys the commercial benefit of a portion of the upside potential of a property, typically with no obligation for operating costs, capital costs, environmental liabilities or reclamation obligations.

The Company's royalty revenues are derived predominantly from: (i) the Lessor Interests on the Fee Lands leased out by the Company and upon which lessees pay lessor royalties to the Company; (ii) the GORR Lands leased by third parties upon which such third parties pay the Company overriding royalties, net profit, production or such other similar forms of royalty encumbrances; (iii) the GRT Lands; and (iv) related activities, including lease issuance bonus consideration and lease rentals.

The Company does not conduct any drilling activity and is not responsible for making any capital expenditures with respect to the Royalty Properties. The Company receives royalty revenue based on the production performance of wells, with the calculation of such royalty revenues payable based, in part, on the market price of oil and/or natural gas and allowances, if any, for certain deductions. Through certain contractual arrangements with third parties, the Company is able to receive its royalty percentage share of production from the Royalty Properties delivered in-kind. The Company currently takes certain crude oil and natural gas royalty volumes in-kind.

Lessor Interests

The Company's royalty revenue is substantially derived from Lessor Interests in respect of producing wells located on the Company's approximately 8.9 million acres of Fee Lands (including coal only titles). For the year ended December 31, 2017, the Lessor Interests provided approximately 75% of the total royalty revenue of the Company, of which royalty revenue derived from production of liquids (crude oil and NGL) and natural gas accounted for approximately 83% and 17%, respectively.

For the year ended December 31, 2017, average net production associated with the Lessor Interests was approximately 16,692 boe/d, with approximately 44.9 MMcfpd of natural gas production, approximately 7,373 bbls/d of oil production and approximately 1,835 bbls/d of NGL production, generating total royalty revenue of approximately $200.3 million. In addition, in 2017, the lease rental income associated with the Lessor Interests was approximately $10.7 million and lease issuance bonus consideration was approximately $67.0 million.

GORR Interests

The GORR Lands are governed by contractual arrangements whereby a royalty interest has been reserved out of the working interest and granted to the Company, and the Company receives such royalty calculated as a share of hydrocarbons produced from the applicable lands. The GORR Interests, with a few exceptions, expire upon the termination of the underlying leases or licenses, which typically occurs after a specified period of time if the lands are not developed within the lease or licence term or when production activity has subsequently ceased.

The granting of a GORR Interest can arise in many instances, including as a result of: (i) the Company farming out working interest rights to another company in exchange for retaining a GORR Interest on production from wells drilled under the farmout agreement; (ii) the Company providing capital in exchange for granting of a GORR Interest or converting a participating interest in a joint venture relationship into a GORR Interest; (iii) the Company, as owner of certain Fee Lands that are in a checkerboard pattern, receiving a GORR Interest on offsetting Crown acreage, achieved in exchange for allowing drilling by third parties of longer horizontal wells across sections that include portions of the Fee Lands or in certain cases where a third party has reviewed the Company's seismic data and acquired a lease or license in respect of the Crown mineral rights; or (iv) various other contractual arrangements.

The Company holds GORR Interests in approximately 7.1 million acres of GORR Lands, substantially all of which are associated with Crown lands. During the year ended December 31, 2017, average net production associated with the GORR Lands was approximately 8,567 boe/d, with approximately 33.2 MMcfpd of natural gas production, approximately 2,192 bbls/d of oil production and approximately 842 bbls/d of NGL production, generating total royalty revenue of approximately $65.6 million. In 2017, the GORR Interests provided approximately 25% of the total royalty revenue of PrairieSky.

GRT Interests

The Company holds approximately 0.2 million acres of GRT Lands. The GRT Interests are governed under trustee arrangements made with financial institutions and are held by virtue of trust unit certificates issued by the financial institution to the unitholders. Each trust unit represents a fractional ownership share of the lessor royalty percentage payable out of the mines and minerals fee title interests in the GRT Lands when leases are granted, and in rare instances may be a fractional ownership of a fee title.

Crown Interest Lands

The Company holds approximately 0.2 million acres of Crown Interest Lands predominately in Alberta which were acquired to complement the Company's Fee Lands and to build land positions in strategic areas for purposes of royalty interest transactions.

Specialized Skill and Knowledge

The Company relies on specialized skills and knowledge to manage the Royalty Properties. The Company employs a strategy of contracting a limited number of consultants and other specialized service providers to supplement the skills and knowledge of its permanent staff in order to manage the Company's business effectively.

Reorganizations

Other than the Reorganization and the Range Royalty Acquisition, there have been no material reorganizations of the Company since January 1, 2014 or proposed for the current financial year.

Personnel

As of December 31, 2017, the Company had 62 full time employees and 3 part-time employees.

Cyclical and Seasonal Nature of Industry

PrairieSky's operational results and financial condition are dependent on the prices received for crude oil and natural gas production. Crude oil and natural gas prices have fluctuated widely during recent years. Commodity prices are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other crude oil and natural gas regions. Declines in commodity prices adversely affect PrairieSky's business and financial condition. See "*Risk Factors - Prices, Markets and Marketing*".

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 crude oil and natural gas producing properties are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the lessees and/or operators of the Royalty Properties as the demand for natural gas rises during cold winter months and hot summer months.

Environmental Considerations

PrairieSky, as a royalty owner, has no direct exposure to environmental claims and regulations and the associated costs. Environmental matters do however impact the lessees and/or operators of the Royalty Properties and therefore indirectly impact PrairieSky. PrairieSky relies on the lessees and/or operators of the Royalty Properties to be in compliance with current environmental rules and regulations. Failure to comply with environmental regulations could result in the imposition of material fines or penalties on the working interest owners and/or the operators or the curtailment of production which may have a material adverse effect on the Company's business and financial condition.

Competitive Conditions

PrairieSky is a member of the petroleum industry, which is highly competitive at all levels. PrairieSky competes with other companies for all of its business inputs, access to commodity markets, acquisition opportunities, available capital and staffing. PrairieSky strives to be competitive by maintaining a strong financial condition and by focusing on building and maintaining strong relationships with high quality lessees, operating a well-established compliance program and identifying new geological plays and ways to enhance development and recovery of hydrocarbons to maximize the value on the Royalty Properties. Management believes that the Company's land ownership structure, and a weighting towards fee simple mineral title ownership, provides a significant competitive advantage compared to other royalty companies.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data

In accordance with NI 51-101, the reserves data associated with the Royalty Properties set forth below is based upon an evaluation prepared by GLJ with an effective date of December 31, 2017, and a preparation date of January 23, 2018, as set forth in the GLJ Report. The GLJ Report evaluated, as at December 31, 2017, the crude oil, natural gas and NGL reserves associated with the Royalty Properties. The tables below summarize the reserves and the net present value of future net revenue attributable to the reserves as evaluated in the GLJ Report based on the GLJ Price Forecast, cost assumptions and supplied operating expenses.

The tables summarize the data contained in the GLJ Report and as a result, may contain slightly different numbers than such reports due to rounding. Also, due to rounding, certain columns may not add exactly.

The net present value of future net revenue attributable to the reserves is stated without provision for interest costs and administrative costs, but after providing for estimated royalties and production and mineral taxes. Future net revenues are presented on a before-and after-tax basis. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the reserves estimated by GLJ represents the fair market value of the reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. There can be no assurance that such price and cost assumptions will be attained and variances could be material. Other assumptions have been made by GLJ and qualifications related to the costs and other matters are included in the GLJ Report. The recovery estimates of the reserves provided herein are estimates only and there is no guarantee that the reserves, as estimated, will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

In preparing the GLJ Report, GLJ relied on certain information provided by third parties associated with the Royalty Properties, which included working and net revenue interest data, public data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, financial data and future development and operating plans for the Royalty Properties, as applicable. Other engineering, historical production, geological or economic data required to conduct the evaluation and upon which the GLJ Report is based was obtained from public records and from non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the independent evaluation, from all sources, was accepted by GLJ as represented.

The Report on Reserves Data by GLJ in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached to this AIF as Appendix A and Appendix B, respectively.

GLJ was engaged by the Company to provide an evaluation of proved and probable reserves. All of the reserves associated with the Royalty Properties are located in the provinces of Alberta, Saskatchewan, Manitoba and British Columbia. As the Company does not hold any working interests in the Royalty Properties, the Company is not responsible for any capital costs associated with the Royalty Properties and, as such, the evaluation of reserves data does not include any undeveloped reserves.

Reserves Data as of December 31, 2017
Forecast Prices and Costs(1)

Summary of Reserves

	Light and Medium Crude Oil		Heavy Crude Oil		Tight Oil		Bitumen		Conventional Natural Gas	
	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)
Reserves Category	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(MMcf)*	*(MMcf)*
Proved										
Developed Producing	-	7,703	-	1,360	-	477	-	1,009	-	85,987
Developed Non-Producing	-	455	-	419	-	92	-	-	-	1,985
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	-	8,158	-	1,779	-	569	-	1,009	-	87,972
Total Probable	-	2,448	-	596	-	163	-	362	-	27,355
Total Proved Plus Probable	-	10,606	-	2,375	-	732	-	1,371	-	115,328

	Shale Gas		Coal Bed Methane		Natural Gas Liquids		Total Oil Equivalent	
	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)	Gross (2)(4)	Net (3)(4)
Reserves Category	*(MMcf)*	*(MMcf)*	*(MMcf)*	*(MMcf)*	*(Mbbl)*	*(Mbbl)*	*(Mboe)*	*(Mboe)*
Proved								
Developed Producing	-	10,825	-	29,308	-	4,330	-	35,900
Developed Non-Producing	-	2,167	-	-	-	89	-	1,746
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	-	12,992	-	29,308	-	4,419	-	37,646
Total Probable	-	3,307	-	9,387	-	1,345	-	11,588
Total Proved Plus Probable	-	16,299	-	38,694	-	5,764	-	49,234

** Numbers may not add due to rounding.*

Notes:
(1) Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions — Forecast Prices and Costs*".
(2) Gross reserves represent the Company's interest in reserves before deduction of royalties and without including any royalty interests.
(3) Net reserves represent the Company's interest in reserves after deduction of royalty obligations plus the Company's royalty interests in reserves.
(4) The Company differs from typical oil and natural gas producers in that all of its interests in reserves are royalty interests with no associated working interests. As a result, there are no gross reserves associated with the Royalty Properties, which may hinder comparison of the Company's reserves with others in the oil and natural gas industry.

Summary of Net Present Values of Future Net Revenue

	Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year)(1)					Unit Value Before Income Tax Discounted at 10%/year(2)	
	0%	5%	10%	15%	20%		
Reserves Category	***M$***	***M$***	***M$***	***M$***	***M$***	***$/boe***	***$/Mcfe***
Proved							
Developed Producing	1,196,503	909,182	739,485	628,013	549,255	20.60	3.43
Developed Non-Producing	70,452	53,318	43,158	36,518	31,875	24.72	4.12
Undeveloped	-	-	-	-	-	-	-
Total Proved	1,266,955	962,500	782,643	664,531	581,129	20.79	3.47
Total Probable	489,907	275,826	183,796	135,215	105,961	15.87	2.64
Total Proved Plus Probable	1,756,861	1,238,327	966,439	799,746	687,090	19.63	3.27

** Numbers may not add due to rounding.*

	Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/year)(1)				
	0%	5%	10%	15%	20%
Reserves Category	***M$***	***M$***	***M$***	***M$***	***M$***
Proved					
Developed Producing	1,190,341	903,169	733,609	622,265	543,625
Developed Non-Producing	65,283	48,370	38,407	31,946	27,464
Undeveloped	-	-	-	-	-
Total Proved	1,255,624	951,539	772,016	654,211	571,090
Total Probable	445,807	242,359	157,083	113,078	87,089
Total Proved Plus Probable	1,701,431	1,193,898	929,099	767,288	658,178

** Numbers may not add due to rounding.*

Notes:
(1) Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions — Forecast Prices and Costs*".
(2) Unit values are based on Company net reserves.

Additional Information Concerning Future Net Revenue (Undiscounted) as of December 31, 2017(1)

	Revenue	Royalties (2)	Operating Costs(3)	Capital Development Costs(3)	Aband. & Recl. Costs(3)	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Reserves Category	***M$***	***M$***	***M$***	***M$***	***M$***	***M$***	***M$***	***M$***
Proved								
Developed Producing	1,209,212	12,709	-	-	-	1,196,503	6,162	1,190,341
Developed Non-Producing	71,012	561	-	-	-	70,452	5,168	65,283
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	1,280,224	13,270	-	-	-	1,266,955	11,331	1,255,624
Total Probable	493,717	3,810	-	-	-	489,907	44,100	445,807
Total Proved Plus Probable	1,773,941	17,080	-	-	-	1,756,861	55,431	1,701,431

** Numbers may not add due to rounding.*

Notes:
(1) Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions — Forecast Prices and Costs*".
(2) Production and mineral taxes payable.
(3) The Company does not hold any working interests in the Royalty Properties. As such, the Company is not responsible for any operating, development or abandonment and reclamation costs associated with estimated net revenues from the reserves attributed to the Royalty Properties.

Future Net Revenue by Production Type as of December 31, 2017 – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes(1)(4) (Discounted at 10% per year)		
	M$	**$/boe**	**$/Mcfe**
Proved Producing			
Light Crude Oil & Medium Crude Oil (combined)(2)	367,784	35.14	5.86
Heavy Crude Oil(2)	45,019	32.60	5.43
Tight Oil2)	19,385	35.17	5.86
Bitumen	30,827	30.54	5.09
Conventional Natural Gas(3)	202,699	13.12	2.19
Shale Gas(3)	22,073	10.33	1.72
Coal Bed Methane	51,698	10.57	1.76
Total Proved Producing	739,485	20.60	3.43
Total Proved			
Light Crude Oil & Medium Crude Oil (combined)(2)	388,941	35.34	5.89
Heavy Crude Oil(2)	57,995	32.20	5.37
Tight Oil2)	22,303	34.67	5.78
Bitumen	30,827	30.54	5.09
Conventional Natural Gas(3)	205,262	13.06	2.18
Shale Gas(3)	25,617	10.00	1.67
Coal Bed Methane	51,698	10.57	1.76
Total Proved	782,643	20.79	3.47
Total Proved Plus Probable			
Light Crude Oil & Medium Crude Oil (combined)(2)	476,079	32.79	5.47
Heavy Crude Oil(2)	75,131	31.24	5.21
Tight Oil2)	27,267	31.96	5.33
Bitumen	41,320	30.13	5.02
Conventional Natural Gas(3)	250,828	12.28	2.05
Shale Gas(3)	30,456	9.51	1.59
Coal Bed Methane	65,358	10.12	1.69
Total Proved Plus Probable	966,439	19.63	3.27

Notes:
(1) Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions — Forecast Prices and Costs*".
(2) Including solution gas and other by-products.
(3) Including by-products but excluding solution gas.
(4) Other Company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company net reserves.

For future net revenue of the total proved reserves before income taxes, discounted at 10%, 64% of the revenue is from crude oil and 36% is from combined natural gas. For the total proved plus probable reserves, 64% of the future net revenue before income taxes, discounted at 10%, is from combined crude oil and 36% is from combined natural gas.

Notes and Definitions

In the tables set forth above and elsewhere in this AIF, the following notes and other definitions are applicable.

Reserve Categories

The determination of crude oil and natural gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods are required to properly use and apply reserves definitions.

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

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

(b) the use of established technology; and

(c) within 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.

Each of the reserves categories may be divided into 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 (e.g., 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 (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves category (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 sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation is 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 reserves 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 estimates are presented. Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

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

A quantitative 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 are 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.

Pricing Assumptions — Forecast Prices and Costs

GLJ employed the following then current pricing, inflation rate and exchange rate assumptions based on the GLJ Price Forecast (2018-01) in estimating reserves data using forecast prices and costs.

	Crude Oil						
Year	**WTI at Cushing, Oklahoma**	**Edmonton Par Price 40^{O} API**	**Hardisty Bow River**	**Hardisty Western Canadian Select**	**Hardisty Heavy Oil 12^{O} API**	**Cromer Light Sour 35^{O} API**	**Exchange Rate(1)**
	($US/bbl)	***($/bbl)***	***($/bbl)***	***($/bbl)***	***($/bbl)***	***($/bbl)***	***($US/$Cdn)***
2018	59.00	70.25	49.39	48.89	39.63	68.85	0.79
2019	59.00	70.25	53.66	53.16	45.71	68.85	0.79
2020	60.00	70.31	56.75	56.25	49.81	68.91	0.80
2021	63.00	72.84	59.76	59.26	52.89	71.38	0.81
2022	66.00	75.61	62.70	62.20	55.89	74.10	0.82
2023-2027	69.00-78.88	78.31-90.22	65.56-77.46	65.06-76.96	58.82-70.72	76.75-88.41	0.83-0.83
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	0.83

Year	Natural Gas	Edmonton Natural Gas Liquids				
	Alberta AECO Spot Prices	Ethanes	Propanes	Butanes	Pentane Plus	Inflation Rate(2)
	($/MMbtu)	*($/bbl)*	*($/bbl)*	*($/bbl)*	*($/bbl)*	*(%/year)*
2018	2.20	6.75	40.40	53.74	76.42	2
2019	2.54	7.95	36.53	49.18	74.68	2
2020	2.88	9.12	35.93	49.22	74.38	2
2021	3.24	10.34	36.06	50.99	77.16	2
2022	3.47	11.14	36.29	52.93	79.88	2
2023-2027	3.58-3.88	11.51-12.53	37.59-43.30	54.82-63.15	82.53-94.43	2
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year

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

During 2017, average sales prices realized in respect of the production associated with the Royalty Properties were $1.81/Mcf for natural gas, $52.99/bbl for total crude oil and $29.80/bbl for NGL.

Reserves Reconciliation

A requirement of NI 51-101 is the provision of a reconciliation on a gross reserves basis. Due to the Company's unique asset base, the tables setting forth the reconciliation of gross reserves do not provide adequate information and are potentially misleading. Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include any royalties receivable. Net reserves are working interests minus royalties payable plus royalties receivable. As substantially all of the Company's assets are royalty interests, they would be excluded in a gross reconciliation table. The Company believes this would hinder an investor's ability to compare PrairieSky's reserves to others in the same industry.

The following reserve reconciliation table is provided as an aid to the investor. The table is based on net reserves and is consistent with disclosure presented by other entities in the royalty business.

Reconciliation of Company Net Reserves
by Principal Product Type
Forecast Prices and Costs

	Light and Medium Crude Oil			Heavy Crude Oil		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*
December 31, 2016	8,846	2,831	11,677	1,766	548	2,314
Product Type Transfers(1)	-	-	-	(153)	(40)	(193)
Adjusted December 31, 2016	8,846	2,831	11,677	1,613	508	2,121
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	1,408	351	1,759	449	104	554
Technical Revisions	790	(597)	193	140	13	153
Acquisitions	156	40	195	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(439)	(177)	(615)	(89)	(30)	(119)
Production	(2,603)	-	(2,603)	(335)	-	(335)
December 31, 2017(2)	8,158	2,448	10,606	1,779	596	2,375

	Tight Oil			Bitumen		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbl)	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*	*(Mbbl)*
December 31, 2016	545	206	751	244	65	309
Product Type Transfers(1)	153	40	193	-	-	-
Adjusted December 31, 2016	698	246	943	244	65	309
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	266	58	324	-	-	-
Technical Revisions	(9)	55	46	31	(1)	29
Acquisitions	7	1	8	1,059	319	1,378
Dispositions	-	-	-	-	-	-
Economic Factors	(98)	(197)	(295)	(65)	(21)	(86)
Production	(295)	-	(295)	(259)	-	(259)
December 31, 2017(2)	569	163	732	1,009	362	1,371

	Conventional Natural Gas			Shale Gas		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcf)	*(MMcf)*	*(MMcf)*	*(MMcf)*	*(MMcf)*	*(MMcf)*
December 31, 2016	87,918	25,056	112,974	9,920	2,912	12,832
Product Type Transfers(1)	-	-	-	-	-	-
Adjusted December 31, 2016	87,918	25,056	112,974	9,920	2,912	12,832
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	6,488	2,066	8,554	4,472	923	5,395
Technical Revisions	14,567	(483)	14,084	479	(538)	(59)
Acquisitions	991	1,028	2,020	45	16	61
Dispositions	-	-	-	-	-	-
Economic Factors	(1,020)	(312)	(1,332)	(14)	(7)	(21)
Production	(20,972)	-	(20,972)	(1,909)	-	(1,909)
December 31, 2017(2)	87,972	27,355	115,328	12,992	3,307	16,299

	Coal Bed Methane			Natural Gas Liquids		
	Proved	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
	(MMcf)	***(MMcf)***	***(MMcf)***	***(Mbbl)***	***(Mbbl)***	***(Mbbl)***
December 31, 2016	33,477	5,776	39,253	3,764	1,099	4,863
Product Type Transfers(1)	-	-	-	-	-	-
Adjusted December 31, 2016	33,477	5,776	39,253	3,764	1,099	4,863
Discoveries	-	-	-	-	-	-
Extensions & Improved Recovery	3	1	4	328	183	511
Technical Revisions	1,464	3,609	5,073	1,326	(17)	1,309
Acquisitions	-	-	-	10	48	58
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	(32)	32	-
Production	(5,636)	-	(5,636)	(977)	-	(977)
December 31, 2017(2)	29,308	9,387	38,694	4,419	1,345	5,764

	Total Oil Equivalent		
	Proved	**Probable**	**Proved Plus Probable**
	(Mboe)	***(Mboe)***	***(Mboe)***
December 31, 2016	37,051	10,373	47,423
Product Type Transfers(1)	-	-	-
Adjusted December 31, 2016	37,051	10,373	47,423
Discoveries	-	-	-
Extensions & Improved Recovery	4,279	1,195	5,473
Technical Revisions	5,029	(116)	4,913
Acquisitions	1,404	582	1,986
Dispositions	-	-	-
Economic Factors	(895)	(446)	(1,341)
Production	(9,221)	-	(9,221)
December 31, 2017(2)	37,646	11,588	49,234

Notes:
(1) Product Type Transfers to align certain reserves previously classified as heavy crude oil, now classified as tight oil.
(2) Columns may not add due to rounding.

For the reserves year ended December 31, 2017, many oil and gas properties received positive technical revisions related to shallower declines or improved well performance. This improvement was most prominent for conventional natural gas and coal bed methane reserves. NGL volumes received a technical revision upwards due to an increase in deep-cut processing. Bitumen reserves increased materially as a result of the Pengrowth GORR Acquisition. The decline in economic factors can be primarily attributed to the decrease in forecasted crude oil and natural gas pricing. The overall impact of these changes is a two percent increase in proved reserves, and a four percent increase in proved plus probable reserves.

Significant Factors or Uncertainties Affecting Reserves Data

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting crude oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. The reserves were evaluated by GLJ who is an independent qualified reserves evaluator.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental regulations.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing economic or regulatory environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end crude oil and natural gas prices and reservoir performance. Such revisions can be either positive or negative.

Future Development Costs

Funding for development costs is the responsibility of the working interest owners on the applicable properties. The Company does not hold any working interests in the Royalty Properties and is not responsible for any development costs on the Royalty Properties. No future development capital is considered in the Company's reserve evaluation and the Company cannot advise as to the sources and costs of funding future development or the impact thereof on disclosed reserves or future net revenue.

Oil and Natural Gas Properties and Wells

The following tables summarize the gross number of wells located on the Royalty Properties in which the Company holds a royalty interest, all of which are located in British Columbia, Alberta, Saskatchewan and Manitoba, and all of which are onshore. As the Company does not hold any working interests in the Royalty Properties or related infrastructure, the net number of wells, or ownership in properties or facilities located on the Royalty Properties is nil.

	Natural Gas(1)		Oil(1)	
Area	**Producing**	**Non-Producing(2)**	**Producing**	**Non-Producing(2)**
Alberta	20,406	-	5,125	-
Saskatchewan	7,752	-	4,699	-
British Columbia	231	-	16	-
Manitoba	2	-	97	-

Notes:
(1) Includes unit wells.
(2) Royalty revenues payable by third parties are based on producing wells located on the Royalty Properties. The Company does not have information from third parties on non-producing wells located on the Royalty Properties.

Properties with No Attributed Reserves

The following table summarizes the undeveloped land holdings of the Company with no attributed reserves as at December 31, 2017 and the acreage which is subject to a lease term expiry within one year.

(thousands of acres)	Fee Lands(1)(3)	GRT Lands(1)(3) Gross Acres(3)	GORR Lands(2)(4) Gross Acres	GORR Lands(2)(4) Gross Acres expiring within one year	Crown Interest Lands(2)(4) Gross Acres	Crown Interest Lands(2)(4) Net Acres	Crown Interest Lands(2)(4) Net Acres expiring within one year
Alberta	3,509	39	2,000	35	210	210	146
Saskatchewan	980	88	459	32	6	6	-
British Columbia	-	-	448	14	-	-	-
Manitoba	424	1	1	-	-	-	-
Other	1	-	63	-	-	-	-
Total	**4,914**	**128**	**2,971**	**81**	**216**	**216**	**146**

** Numbers may not add due to rounding.*

Notes:
(1) Fee lands with multiple leases under the same surface area have been calculated on an aerial basis, and as such have only been counted once.
(2) Undeveloped lands are calculated by adding the surface area covered by individual leases or agreements. In certain limited circumstances where the Company holds interests under the same surface area pursuant to different leases or agreements, the acreage with respect to all such leases or agreements are added together.
(3) The petroleum and/or natural gas rights associated with certified title to Fee Lands and GRT Lands under superior trust agreements are held in perpetuity. The number of uncertified titles and inferior trust agreements held by the Company are de minimus. As such, there is no meaningful number of gross acres for which the Company's interests will expire during 2018.
(4) Some of this acreage may qualify to be continued by the working interest owners pursuant to other operations on the lands or offsetting lands as allowed by the regulations. Additionally, although the Company does not directly conduct operations on these lands, it makes every possible effort to have third parties actively develop the lands prior to lease expiries and therefore anticipates only a small percentage of this acreage to expire during this period.

Tax Horizon

The Company is presently cash taxable. The statutory corporate income tax rate applicable to the Company in 2017 was approximately 27% and the Company recognized current income taxes of $11.6 million in net earnings. A corporation's taxable income is based on total revenue, expenses and other deductions, which in the case of the Company will vary depending on the amount of royalty revenue received as a result of fluctuations in commodity prices and development activities on the properties in which it holds interests, as well as other revenues related to leasing activity on Fee Lands. At December 31, 2017, the Company had $1.6 billion of tax pools which can be used to offset future taxable income.

Costs Incurred

Expenditure	**Year Ended December 31, 2017 ($M)**
Property Acquisition Costs:	
Proved Properties	59.3
Unproved Properties	321.2
Total	380.5

Production Estimates

The following table discloses for each product type the gross and net volume of production estimated by GLJ for the year ended December 31, 2018, in the estimates of gross and net proved and gross and net probable reserves disclosed above under the heading "*Reserves and Other Oil and Gas Information — Disclosure of Reserves Data*".

Reserves Category	Light and Medium Crude Oil		Heavy Crude Oil		Tight Oil		Bitumen	
	Gross (1)(2)	Net (3)(4)	Gross (1)(2)	Net (3)(4)	Gross (1)(2)	Net (3)(4)	Gross(1)(2)	Net (3)(4)
	(bbl/d)		(bbl/d)		(bbl/d)		(bbl/d)	
Proved								
Developed Producing	-	4,520	-	748	-	364	-	841
Developed Non-Producing	-	378	-	41	-	60	-	-
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	-	4,898	-	788	-	423	-	841
Probable	-	328	-	21	-	88	-	25
Total Proved Plus Probable	-	5,226	-	810	-	511	-	867

Reserves Category	Natural Gas							
	Conventional		Shale Gas		Coal Bed Methane		NGL	
	Gross (1)(2)	Net (3)(4)	Gross (1)(2)	Net (3)(4)	Gross (1)(2)	Net (3)(4)	Gross (1)(2)	Net (3)(4)
	(Mcf/d)		(Mcf/d)		(Mcf/d)		(bbl/d)	
Proved								
Developed Producing	-	41,393	-	4,209	-	11,276	-	1,957
Developed Non-Producing	-	1,427	-	1,264	-	-	-	54
Undeveloped	-	-	-	-	-	-	-	-
Total Proved	-	42,820	-	5,473	-	11,276	-	2,011
Probable	-	2,929	-	299	-	844	-	91
Total Proved Plus Probable	-	45,749	-	5,772	-	12,119	-	2,102

Reserves Category	Total Oil Equivalent	
	Gross (1)(2)	Net (3)(4)
	(boe/d)	
Proved		
Developed Producing	-	17,909
Developed Non-Producing	-	981
Undeveloped	-	-
Total Proved	-	18,890
Probable	-	1,233
Total Proved Plus Probable	-	20,122

Notes:
(1) Gross production represents the Company's interest in production before deduction of royalties and without including any royalty interests.
(2) The Company differs from oil and natural gas producers in that all of its interests in reserves are royalty interests with no associated working interests. As a result, there are no gross reserves associated with the Royalty Properties, which may hinder comparison of the Company's reserves with others in the oil and natural gas industry.
(3) Net production represents the Company's interest in production after deduction of royalty obligations plus the Company's royalty interests in production.
(4) Columns may not add due to rounding.

Production History

The following table summarizes production, product prices received, royalties paid (production and mineral tax expense), administrative expenses and resulting netback for the periods indicated below.

	Annual	2017			
	2017	Q4	Q3	Q2	Q1
Average daily production(1)					
Natural Gas *(MMcfpd)*	78.1	75.2	75.3	80.6	81.6
Crude Oil (*bbl/d*)	9,565	9,419	9,033	9,609	10,214
NGL *(bbl/d)*	2,677	2,454	2,600	2,664	2,998
Total *(boe/d)*	25,259	24,406	24,183	25,706	26,812
Average price realized(2)					
Natural Gas *($/Mcf)*	1.81	1.56	1.25	2.15	2.26
Crude Oil (*$/bbl*)	52.99	58.35	47.61	52.98	52.81
NGL *($/bbl)*	29.80	34.80	25.02	28.60	30.94
Total *($/boe)*	28.84	30.82	24.36	29.51	30.45
Production and mineral tax expense					
Natural Gas *($/Mcf)*	0.06	0.08	0.08	(0.03)	0.10
Crude Oil (*$/bbl*)	1.29	1.22	1.46	0.60	1.86
NGL *($/bbl)*	-	-	-	-	-
Total *($/boe)*	0.66	0.71	0.81	0.13	0.99
Administrative expense(3)					
Natural Gas *($/Mcf)*	0.61	0.54	0.71	0.76	0.44
Crude Oil (*$/bbl*)	3.64	3.22	4.20	4.69	2.58
NGL *($/bbl)*	-	-	-	-	-
Total *($/boe)*	3.26	2.89	3.78	4.10	2.32
Netback received(4)					
Natural Gas *($/Mcf)*	1.14	0.94	0.44	1.42	1.72
Crude Oil (*$/bbl*)	48.06	53.91	41.95	47.69	48.37
NGL *($/bbl)*	29.80	34.80	25.02	28.60	30.94
Total *($/boe)*	24.92	27.22	19.77	25.28	27.14

Notes:
(1) Represents net production.
(2) Excludes coal, sulphur and other revenue.
(3) PrairieSky does not incur operating expenses. Administrative expenses include expenses associated with land administration, accounting and auditing functions necessary to administer and collect royalty payments and are allocated to natural gas and oil based on each product's share of that total product revenue.
(4) Netbacks are calculated by subtracting royalties paid (production and mineral tax expense) and administrative expense from revenues.

Description of Properties

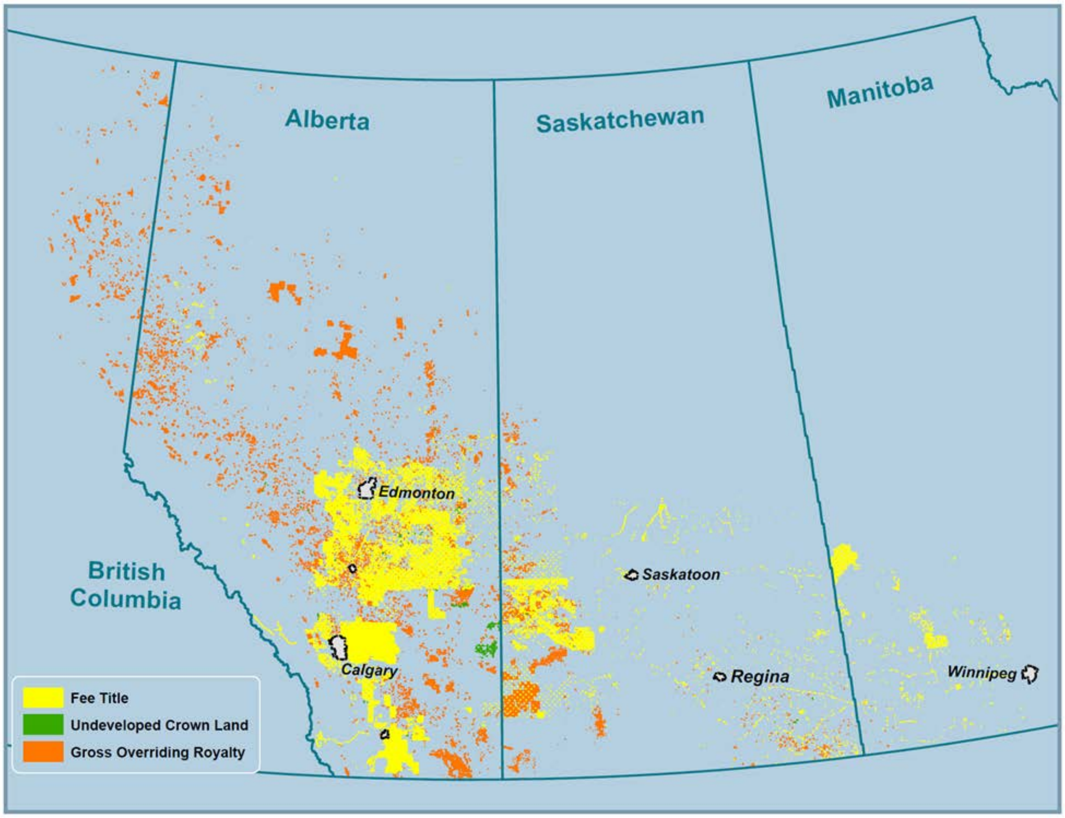
The assets of PrairieSky are comprised of: (i) the Fee Lands, encompassing approximately 7.8 million acres, excluding coal only titles of approximately 1.1 million acres; (ii) the Lessor Interests; (iii) the GORR Interests, encompassing approximately 7.1 million acres of the GORR Lands; (iv) the GRT Interests, encompassing approximately 0.2 million acres of the GRT Lands; (v) approximately 0.2 million acres of Crown Interest Lands; (vi) the Seismic Licence to certain Encana proprietary seismic data and seismic data acquired pursuant to multiple acquisitions, together encompassing approximately 43,000 kilometers of 2D seismic and approximately 13,000 square kilometers of 3D seismic; and (vii) certain other related assets.

The Fee Lands are located in the Western Canadian Sedimentary Basin, predominantly in the provinces of Alberta and Saskatchewan.

Over 20,000 leases are currently active on the Fee Lands and over 350 lessees are engaged in exploring for and producing oil and natural gas on the Fee Lands.

Map of PrairieSky Fee Lands, GORR Interests and Other Interests

Below is a map of the Royalty Properties indicating those lands which are Fee Lands, GORR Interests (including GRT Interests) and Crown Interest Lands.



Lands

The Company has one of the largest independently-owned portfolios of fee simple mineral title in Canada with approximately 8.9 million acres of Fee Lands, of which approximately 7.8 million acres are comprised of petroleum and/or natural gas rights, without the inclusion of coal rights and 1.1 million acres including coal only rights. For the period ended December 31, 2017, royalty revenue from the Fee Lands accounted for approximately 75% of the total royalty revenue of PrairieSky.

The Fee Lands include a geologically diverse portfolio of properties that span the stratigraphic column from surface to basement. There is potential for the same section of land to be leased and re-leased on the basis of geological grouping, therefore allowing multiple lessees the right to drill and explore for, and ultimately produce from, different formations depending on the particulars of their leasing arrangement. Geological groups that form part of the Fee Lands include: (i) Surface to Top Colorado, focusing on shallow gas and Belly River oil development; (ii) the Colorado Group, which includes the Cardium Formation and the Viking Formation in both Alberta and Saskatchewan; (iii) the Mannville Group, which includes the Detrital/Basal Quartz/Ellerslie/Ostracod, as well as the Glauconitic Formation and Upper Mannville Fahler/Wilrich/Notikewin; (iv) the Jurassic to Base Mississippian, which includes the Rock Creek, Nordegg, Rundle Group, Banff, Midale and Bakken Formations; and (v) the Devonian, which includes the Nisku and the Duvernay Formations.

GORR Lands

The Company holds GORR Interests in approximately 7.1 million acres of GORR Lands. The substantial majority of the GORR Lands were acquired in connection with the Range Royalty Acquisition and the CNRL Royalty Acquisition. Most recent drilling activities on the GORR Lands were predominantly focused on the Viking Formation in southwestern Saskatchewan and Alberta, the Wilrich and Duvernay Formations at Edson, the Lloydminster, Cummings and Rex Formations in Central Alberta as well as on both the Lindbergh and Onion Lake thermal projects, the Duvernay Formation at Willesden Green, the Montney/Doig, Cardium, Spirit River and Dunvegan in the Deep Basin and the Montney/Doig in northeast British Columbia.

GRT Lands

The Company holds approximately 0.2 million acres of GRT Lands which represent minor fractional shares of lessor royalty interests reserved out of fee title lands throughout the Western Canadian Sedimentary Basin.

Crown Interest Lands

The Company holds approximately 0.2 million acres of Crown Interest Lands, predominately in Alberta, which were acquired to complement the Company's checkerboard fee title position and to build land positions in strategic areas for purposes of royalty interest transactions.

Certain Other Mines and Mineral Rights

Coal rights, precious stone and other mines and mineral rights, including lithium, in addition to oil and natural gas, are included in substantially all the Fee Lands. The Fee Lands include a royalty interest in a third-party operated Highvale coal mine in central Alberta, which is subject to a coal royalty settlement agreement with the third party. The Company does not consider the coal mining lease material to its business and does not expect any future royalty revenues from such lease. Additionally, due to the low commodity price outlook of coal, current estimates of mining and transportation costs in Alberta, or lack of commercial development at this time, the Company does not currently consider coal, precious stone or these other mineral rights material to its business.

BORROWINGS

PrairieSky has an unsecured $25 million extendible operating credit facility (the *Credit Facility*). The Credit Facility does not have a borrowing base restriction and has a two-year term, extendible annually for up to three years, subject to certain requirements. Outstanding amounts on the Credit Facility bear interest at the lender's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees. The Credit Facility requires the Company to comply with the following financial covenants at the end of each fiscal quarter: adjusted consolidated senior debt to adjusted consolidated earnings before interest, taxes, and all non-cash items including depreciation, depletion and amortization (*EBITDA*) ratio must not exceed 3.0:1, adjusted consolidated total debt to adjusted consolidated EBITDA ratio must not exceed 4.0:1 and adjusted consolidated total debt to capitalization ratio must not exceed 50%. EBITDA does not have any standardized meaning as prescribed by international financial reporting standards and may not be comparable to similarly defined measures presented by other entities. As at December 31, 2017, the Company had $25 million of available capacity under the Credit Facility and $nil debt.

INDUSTRY CONDITIONS

Companies carrying on business in the oil and natural gas sector are subject to extensive controls and regulation imposed through legislation of the federal government and the provincial governments where the companies have assets or operations, all of which should be carefully considered by investors in the oil and natural gas industry. Although governmental legislation is a matter of public record, the Company is unable to predict what additional legislation or amendments governments may enact in the future.

The unique nature of the Royalty Properties is expected to allow the Company to benefit from the upside potential of such properties at a reduced risk relative to traditional exploration and production companies. This advantage is a result of collecting royalty payments in respect of the Royalty Properties rather than directly conducting operations to explore for, develop or produce petroleum or natural gas, which has a higher regulatory burden. However, these regulations may impact the royalties received by the Company as an indirect participant in the development of crude oil and natural gas on its Royalty Properties. In addition, if the strategy of the Company were to change in the future such that it becomes a direct participant in the development of its properties, whether as working interest owner or operator in respect of the Fee Lands that are currently undeveloped, or otherwise, the aforementioned industry regulation would become the burden of the Company in respect of such development. The discussion below outlines certain pertinent conditions and regulations that impact the oil and natural gas industry in western Canada.

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers, which results in the market determining the price of crude oil. Worldwide supply and demand factors primarily determine crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

The price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids

The price of condensate and other natural gas liquids such as ethane, butane and propane (*NGL*) sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGL, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

Crude oil, natural gas and NGL exports from Canada are subject to the *National Energy Board Act* (Canada) (the *NEB Act*) and the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the *Part VI Regulation*). The NEB Act and the Part VI Regulation authorize crude oil, natural gas and NGL exports under either short-term orders or long-term licences. To obtain a crude oil export licence, a mandatory public hearing with the National Energy Board (the *NEB*) is required, which is no longer the case for natural gas and NGLs. For natural gas and NGL, the NEB uses a written process that includes a public comment period for impacted persons. Following the comment period, the NEB completes its assessment of the application and either approves or denies the application. For natural gas, the maximum duration of an export licence is 40 years and, for crude oil and other gas substances (e.g. NGL), the maximum term is 25 years. All crude oil, natural gas and NGL licences require the approval of the cabinet of the Canadian federal government.

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from the cabinet of the Canadian federal government. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGL) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m^3 per day.

As to price, 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 NEB and the federal government.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGL outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from western Canada to the United States and other international markets. Although certain pipeline or other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and political factors. The transportation capacity deficit is not likely to be resolved quickly given the significant length of time required to complete major pipeline or other transportation projects once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGL in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

Producers negotiate with pipeline operators (or other transport providers) to transport their products, which may be done on a firm or interruptible basis. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low pricing relative to other markets in the last several years. Transportation availability is highly variable across different areas and regions, which can determine the nature of transportation commitments available, the numbers of potential customers that can be reached in a cost-effective manner and the price received.

Developing a strong network of transportation infrastructure for crude oil, natural gas and NGL, including by means of pipelines, rail, marine and trucks, in order to obtain better access to domestic and international markets has been a significant challenge to the Canadian oil and natural gas industry. Improved means of access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, would help to alleviate the pressures of pricing discussed. Several proposals have been announced to increase pipeline capacity out of Western Canada, to reach Eastern Canada, the United States and international markets via export shipping terminals on the west coast of Canada. While certain projects are proceeding, the regulatory approval process as well as economic and political factors for transportation and other export infrastructure has led to the delay of many pipeline projects or their cancellation altogether.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the NEB and the cabinet of the federal government. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government recently introduced draft legislation to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes to the draft legislation will be made before the legislation is brought into force. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments as well as court challenges on various issues such as indigenous title, the government's duty to consult indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. Export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing, other companies may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production). Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, government decision-making, regulatory uncertainty, opposition from environmental and indigenous groups, and changing market conditions, have resulted in the cancellation or delay of many of these projects.

The North American Free Trade Agreement and Other Trade Agreements

The North American Free Trade Agreement (*NAFTA*) among the governments of Canada, the United States and Mexico came into force on January 1, 1994. Under the terms of NAFTA, Canada remains 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. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

In 2017, the United States government announced its intention to renegotiate NAFTA. As a result, Canada, the United States and Mexico began renegotiating the terms of NAFTA in mid-2017. The United States has also suggested that it might give notice of the termination of NAFTA if it is not satisfied with the outcome of the renegotiations. If the United States does give notice of its intent to terminate or withdraw from NAFTA, the earliest such termination or withdrawal could occur would be six months after such notice is given. The renegotiations are still underway and the outcomes of such negotiations remain unclear, but as the United States remains by far Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGL from Canada, any changes to, or termination of, NAFTA could have an impact on Western Canada's oil and natural gas industry at large, including the Company's business.

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement (*CETA*), which provides for duty-free, quota-free market access for Canadian oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In addition, Canada and ten other countries recently concluded discussions and agreed on the draft text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership (*CPTPP*), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The text of CPTPP has not been finalized or published and the agreement remains subject to ratification by the governments of each of the countries involved. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and natural gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and gas producers to benefit from such trade agreements.

Land Tenure

The respective provincial governments (i.e. the Crown), predominantly own the mineral rights to crude oil and natural gas located in western Canada, with the exception of Manitoba (where the Crown only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. The leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

Each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba have 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 licence. Additionally, the provinces of Alberta and British Columbia have shallow rights reversion for shallow, non-productive geological formations for new leases and licences.

To develop crude oil and natural gas resources, it is necessary to have access to the surface lands as well as the mineral interest. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in the provinces of Alberta, British Columbia, Saskatchewan and Manitoba. In each of the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 30% and 80%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada (*IOGC*), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable indigenous peoples, for exploration and production of crude oil and natural gas on indigenous reservations.

The Fee Lands consist of fee simple mineral titles privately owned by the Company. Certain of the Fee Lands are encumbered and governed, as applicable, by leases granted on such lands (including those issued to Encana pursuant to the Encana Royalty Acquisition). The Lessor Interests consist of the rights of the Company as set forth under such leases.

The GORR Interests are royalty interests that are granted or carved out of leasehold interests (created through the issuance of a lease by the Crown or fee simple mineral title owner). As such, the continued existence and value of the GORR Interests is dependent upon the validity and terms of the leasehold interest out of which they were granted.

In respect of the GORR Interests granted out of Crown leases, in addition to the varying terms and conditions set forth in provincial legislation, as discussed above, the Provinces of Alberta, British Columbia, Saskatchewan, and Manitoba have implemented legislation providing for the reversion to the Crown of mineral rights to non-productive geological formations at the conclusion of the primary term of a lease or license.

Royalties and Incentives

General

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 and crude oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the freehold mineral owner and the lessee (as is the case with the Fee Lands that the Company owns and leases to third parties), although production from such lands is subject to certain provincial taxes (including Freehold Mineral Tax). 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 Crown 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 substance produced.

Occasionally the governments of western Canada's provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are often introduced when commodity prices are low to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGL.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

The Company has the flexibility to negotiate and adapt its royalty arrangements with third parties to affect the profitability of the exploration, development and production of crude oil and natural gas related to its Lessor Interests or GORR Interests in the appropriate circumstances, including consideration of the existing royalty regime established by the Province of Alberta (as described below) and any amendments to that regime.

Alberta

In Alberta, the provincial government royalty rates apply to Crown-owned mineral rights. In 2016, Alberta adopted a modernized Alberta royalty framework (the *Modernized Framework*) that applies to all wells drilled after January 1, 2017. The previous royalty framework (the *Old Framework*) will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework.

The Modernized Framework applies to all hydrocarbons other than oil sands which remain subject to the Old Framework as detailed below. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry’s average drilling and completion costs as determined by the Alberta Energy Regulator (the *AER*) on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGL is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are also required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

Oil sand production is also subject to Alberta's royalty regime. The Modernized Framework did not change the oil sands royalty framework. 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% and 9% depending on the market price of crude oil, determined using the average monthly price, expressed in Canadian dollars, for West Texas Intermediate crude oil at Cushing, Oklahoma. Rates are 1% when the market price of crude oil is less than or equal to $55 per barrel and increase for every dollar of market price of crude oil increase to a maximum of 9% when crude 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% and 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 crude oil increase above $55 up to 40% when crude oil is priced at $120 or higher.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

Freehold Mineral Taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold Mineral Taxes are calculated 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 (revenues less allowable costs), the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties.

British Columbia

Producers of crude oil in British Columbia receive royalty invoices from the provincial government each month for every well or unitized tract that is producing and/or reporting sales. The royalty calculation takes into account the production of crude oil on a well-by-well basis, which can be up to 40%, based on factors such as the volume of crude oil produced by the well or tract and the crude oil vintage, which depends on density of the substance and when the crude oil pool was discovered. Royalty rates are reduced on low-productivity wells and other wells with applicable royalty exemptions to reflect higher per-unit costs of exploration and extraction.

Producers of natural gas and NGL in British Columbia receive royalty invoices each month for every well or unitized tract that is producing and/or reporting sales. Different royalty rates apply for natural gas, NGL and natural gas by-products. For natural gas, the royalty rate can be up to 27% of the value of the natural gas and is based on whether the gas is classified as conservation gas or non-conservation gas, as well as reference prices and the select price. For NGL and condensates, the royalty rate is fixed at 20%.

The royalties payable by each producer will vary depending on the types of wells and the characteristics of the substances being produced. Additionally, the Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

Producers of crude oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For crude oil, the applicable freehold production tax is based on the volume of monthly production, which is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on a reference price, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGL is a flat rate of 12.25%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale depending on the total number of hectares owned by the entity.

Saskatchewan

In Saskatchewan, the Crown owns approximately 80% of the crude oil and natural gas rights, with the remainder being freehold lands. For Crown lands, taxes (the *Resource Surcharge*) are applicable to revenue generated by entities focused on crude oil and natural gas operations. The Resource Surcharge rate is 3% of the value of sales of all crude oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For crude oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales.

In addition to the Resource Surcharge, the Crown royalty payable in respect of crude oil depends on the type and vintage of crude oil, the quantity of crude oil produced in a month, the value of the crude oil produced and specified adjustment factors determined monthly by the provincial government. The ultimate royalty payable ranges from 5% to 20% depending on the classification of the crude oil, and additional marginal royalty rates may apply, between 30% and 45%, where average wellhead prices received are above base prices. This means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

The amount payable as a Crown royalty in respect of production of natural gas and NGL is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, the classification of the natural gas and the finished drilling date of the respective well. Similar to crude oil royalties, the royalties payable on natural gas will range from 5% to 20%, and additional marginal royalty rates may apply between 30% to 45%, where average wellhead prices are above base prices. Again, this means that producers may pay varying royalties each month, depending on pricing factors, governmental adjustments and the underlying characteristics of the producer's assets.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, with targeted programs in effect for certain vertical crude oil wells, exploratory gas wells, horizontal crude oil and natural gas wells, enhanced crude oil recovery wells and high water-cut crude oil wells.

For production from freehold lands, producers must pay a freehold production tax. The freehold production tax is determined by first calculating the Crown royalty rate, and then subtracting a calculated production tax factor which currently ranges between 6.9 and 12.5 depending on the designation of the production. The minimum rate for freehold production tax can be zero. This means that the ultimate tax payable to the

Crown by producers on freehold lands will vary based on the underlying characteristics of the producer's assets. In addition, a mineral rights tax is charged to mineral rights holders which requires payment on an annual basis at the rate of $1.50 per acre owned.

Manitoba

In Manitoba, the Crown owns approximately 20% of the crude oil and natural gas rights in the province, with the remainder being freehold lands. The royalty amount payable on crude oil produced from Crown lands depends on the classification of the crude oil produced. Royalty rates on crude oil are calculated on a sliding scale with a range of 0% to 40% and are based on the monthly crude oil production from a spacing unit, or crude oil production allocated to a unit tract under a unit agreement or unit order. For horizontal wells, the royalty on crude oil produced from Crown lands is calculated based on the amount of crude oil production allocated to a spacing unit in accordance with the applicable regulations. As such, the royalty payable by producers will vary depending on the underlying characteristics of the producer's assets.

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

The Government of Manitoba maintains a Drilling Incentive Program (the *Program*) with the intent of promoting investment in the sustainable development of petroleum resources by providing royalty holidays. The Program consists of benefits that are specific to certain vertical, exploration and deep wells, as well as wells undergoing major workovers, wells for solution gas and wells converted to injection wells.

Producers of crude oil and natural gas from freehold lands in Manitoba are required to pay monthly freehold production taxes. The freehold production tax payable on crude oil is calculated on a sliding scale between 0% and 40% based on the monthly production volume and the classification of the crude oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold, calculated for each production month.

Freehold and Other Types of Non-Crown Land Royalties and Taxes

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract.

In addition to the royalties payable to the mineral owners, producers of crude oil and natural gas from freehold lands in each of the western Canadian provinces are required to pay production and acreage taxes. Production taxes, including Freehold Mineral Taxes, are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the production and acreage taxes payable in each of the western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, the exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific indigenous group. Ultimately, the relevant indigenous group must approve the terms.

Regulatory Authorities and Environmental Regulation

General

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 are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and natural 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 regulations 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 (*GHG*) 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 both the federal 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 including interprovincial pipelines.

On June 20, 2016, the federal government launched a review of current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the Canadian Energy Regulator (*CER*). Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the *Agency*) would replace the Canadian Environmental Assessment Agency. It appears that additional categories of projects may be included within new impact assessment process, such as large-scale wind power facilities and in-situ oil sands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders such as the public and indigenous groups prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a panel review; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the Minister of Environment and Climate Change or the cabinet of the federal government; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. As to the proposed CER, many of its activities would be similar to the NEB, albeit with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The eventual effects of the proposed regulatory scheme on proponents of major projects remains unclear.

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament is still considering the bill, which passed second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals being located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

The AER is the single regulator responsible for all resource development in Alberta. The AER is responsible for ensuring 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 AER'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 intended to be 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. Its approach 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 AER 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.

The Government of Alberta's land-use policy for surface land in Alberta 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. As a result, several regional plans have been implemented and others are in the process of being implemented. These regional plans may affect further development and operations in such regions.

British Columbia

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

Saskatchewan

The Saskatchewan Ministry of the Economy, Petroleum Branch, is the primary regulator of crude oil and natural gas activities in the province. *The Oil and Gas Conservation Act* (the *SKOGCA*) governs the regulation of resource development operations in the province in conjunction with *The Oil and Gas Conservation Regulations, 2012* (the *OGCR*) and *The Petroleum Registry and Electronic Documents Regulations* (the *Registry Regulations*). The aim of the SKOGCA and the associated regulations is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. The Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Manitoba

In Manitoba, the Petroleum Branch of the Department of Growth, Enterprise and Trade develops, recommends, implements and administers policies and legislation aimed at the sustainable, orderly, safe and efficient development of crude oil and natural gas resources. Crude oil and natural gas exploration, development, production and transportation are subject to regulation under *The Oil and Gas Act* (the *MBOGA*), *The Oil and Gas Production Tax Act* and related regulations and guidelines.

Liability Management Rating Programs

Alberta

The AER administers the Licensee Liability Rating Program (the *AB LLR Program*). The AB LLR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* (the *OGCA*) 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 AB LLR Program if a licensee or working interest participant (*WIP*) becomes insolvent or is unable to meet its obligations. The Orphan Fund is funded through a levy on licensees in the AB LLR Program and is administered by the AER. The AB LLR Program is designed to minimize the risk unfunded liabilities of licensees pose to the Orphan Fund and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month and where a security deposit is deemed to be required, the failure to post any required amounts may result in the initiation of enforcement action by the AER. The AER publishes the liability management rating for each licensee on a monthly basis on its public website.

In *Redwater Energy Corporation (Re)* (*Redwater*), the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA, including the AB LLR Program, and the *Bankruptcy and Insolvency Act* (the *BIA*). This ruling meant that receivers and trustees have the right to renounce assets within insolvency proceedings, which was affirmed by a majority of the Alberta Court of Appeal. Such a conflict renders the AER'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 financial resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA. This decision is currently under appeal to the Supreme Court of Canada, with final resolution expected in 2018.

In response to Redwater, the AER issued several bulletins and interim rule changes to govern while the case is appealed and to allow the Government of Alberta to develop appropriate regulatory measures to adequately address environmental liabilities. The AER's *Directive 067: Eligibility Requirements for*

Acquiring and Holding Energy Licences and Approvals, which deals with licence eligibility to operate wells and facilities, was amended and now requires extensive corporate governance and shareholder information, with a particular focus on any directors and officers that have been subject to insolvency proceedings at previous companies in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all are assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have a liability management rating (*LMR*), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer, or to otherwise prove that it can satisfy its abandonment and reclamation obligations. The AER may make further rule changes in response to Redwater at any time, especially as the case heads towards a final determination, which means that additional obligations and/or different requirements may be forthcoming.

The AER has also implemented the Inactive Well Compliance Program (the *IWCP*) to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* (*Directive 013*). The IWCP 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 IWCP into compliance with the requirements of Directive 013 within five 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 IWCP is available on the AER's Digital Data Submission system. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. The IWCP completed its second year on March 31, 2017. Overall, the AER has announced that licensees brought 19% of non-compliant wells in the IWCP into compliance with AER requirements in the second year of the IWCP.

British Columbia

The Commission oversees a similar Liability Management Rating Program (the *BC LMR Program*), which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the BC LMR Program, the Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets (i.e., an LMR below a ratio of 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework. The Commission has announced that it is working to determine how best to manage risks in light of the Redwater decision, so changes may be forthcoming.

Saskatchewan

The Ministry of the Economy administers the Licensee Liability Rating Program (the *SK LLR Program*). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to the orphan fund (the *Oil and Gas Orphan Fund*) established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets (i.e., an LLR below a ratio of 1.0) to post a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month for all licensees of crude oil, natural gas and service wells and upstream crude oil and natural gas facilities. On August 19, 2016, the Ministry of the Economy released a notice to all operators introducing interim measures in response to Redwater. Among other things, the Ministry announced that it considers all licence transfer applications non-routine as the Ministry does not strictly rely on the standard LMR calculation in evaluating deposit requirements, and that further changes may be forthcoming.

Manitoba

To date, the Government of Manitoba has not implemented a liability management rating program similar to those found in the other Western Canadian provinces. However, operators of wells licensed in the province are required to post a performance deposit to ensure that the operation and abandonment of wells and the rehabilitation of sites occurs in accordance with the MBOGA and the *Drilling and Production Regulations*. The MBOGA has also established the Abandonment Fund Reserve Account (the *Abandonment Fund*). The Abandonment Fund is a source of funds that may be used to operate or abandon a well when the licensee or permittee fails to comply with the MBOGA. The Abandonment Fund may also be used to rehabilitate the site of an abandoned well or facility or to address any adverse effect on property caused by a well or facility. Deposits into the Abandonment Fund are comprised of non-refundable levies charged when certain licences and permits are issued or transferred as well as annual levies for inactive wells and batteries.

Climate Change Regulation

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.

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 the Company's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the *UNFCCC*) since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of February 1, 2018, 174 of the 197 parties to the convention have ratified the Paris Agreement.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the *Framework*). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne, increasing annually until it reaches $50/tonne in 2022. A draft legislative proposal for the federal carbon pricing system was released on January 15, 2018. This system would apply in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards in 2018. Four provinces currently have carbon pricing systems in place that meet federal requirements (Alberta, British Columbia, Ontario and Quebec). The federal government will accept comments on the draft legislative proposals to implement the federal carbon pricing system until February 12, 2018.

On May 27, 2017, the federal government published draft regulations to reduce emissions of methane from the crude oil and natural gas sector. The proposed regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes, by introducing new control measures. Among other things, the proposed regulations limit how much methane upstream oil and gas facilities are permitted to vent. Facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce GHG emissions by about 20 megatonnes by 2030.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the *CLP*). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emissions limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The *Climate Leadership Act* came into force on January 1, 2017 and enabled a carbon levy that increased from $20 to $30 per tonne on January 1, 2018. The levy is anticipated to increase again in 2021 in line with the federal legislation. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing a 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

The *Carbon Competitiveness Incentives Regulation* (the *CCIR*), which replaces the *Specified Gas Emitters Regulation*, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce emissions by 20 million tonnes by 2020 and 50 million tonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. The CCIR compliance obligations will be reduced by 50% and 25% for 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of 1%, beginning in 2020. The Government of Alberta intends for this strategy to align with the federal Framework.

The Government of Alberta also signaled its intention through its CLP 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 was 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.

British Columbia

On August 19, 2016, the Government of British Columbia launched its Climate Leadership Plan, which aims to reduce British Columbia's net annual emissions by up to 25 million tonnes below current forecasts by 2050 and recommit the province to achieving its target of reducing emissions by 80% below 2007 levels by 2050. Additionally, British Columbia seeks to generate at least 93% of its electricity from clean or renewable sources and build the infrastructure necessary to transmit it. The legislation established no date for this target.

British Columbia was also the first Canadian province to implement a revenue-neutral carbon tax. In 2012, the carbon tax was frozen at $30/tonne. However, in its September update to the 2017/2018 Budget, the Government announced an increase in the carbon tax to $35/tonne in April 2018.

On January 1, 2016, the Greenhouse Gas Industrial Reporting and Control Act (the *GGIRCA*) came into effect, which streamlined the regulatory process for large emitting facilities. The GGIRCA sets out various performance standards for different industrial sectors and provides for emissions offsets through the purchase of credits or through emission offsetting projects.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced the *Management and Reduction of Greenhouse Gases Act* (the *MRGGA*) to regulate GHG emissions in the province. The MRGGA, partially proclaimed into force on January 1, 2018, establishes a framework to reduce GHG emissions by 20% of 2006 levels by 2020. On October 18, 2016, the Government of Saskatchewan released a White Paper on Climate Change, resisting a carbon tax and committing to an approach that focuses on technological innovation and adaptation.

Manitoba

Manitoba has not yet implemented a climate change policy; however, in 2016, Manitoba's Premier stated that the Province would not implement a cap-and-trade system, but would instead consider a carbon tax. In March 2017, the Government of Manitoba initiated a public consultation on a proposed a Made-in Manitoba Climate and Green Plan which was released on October 27, 2017. The Plan proposes a $25/tonne carbon levy that, unlike the federal backstop, will not increase over time. It also proposes an output-based pricing system for large emitters beginning in 2019.

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the *ESTMA*) came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD$100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

RISK FACTORS

The Company is subject to both risks that directly affect its business and operations, as well as indirect risks that impact third parties or industry generally. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Company's business, the business of third parties with whom the Company conducts business, and the oil and natural gas business generally.

Although the Company does not directly conduct operations but instead collects royalty payments in respect of the Royalty Properties as an indirect participant in the development of such properties, its business, financial condition, results of operations and prospects are linked to the risks that impact the oil and natural gas industry generally and in particular those which affect the lessees and/or operators that have or will have arrangements with the Company in respect of the Royalty Properties. Accordingly, where applicable, the following risk factors should be read in the context of both their direct and indirect (through such lessees and/or operators) impact on the Company's business and financial condition.

Dependence on Lessees and/or Operators

The Company is dependent on lessees and/or operators of the Royalty Properties.

Other exploration and production companies are the lessees and/or operators of the Royalty Properties. The Company has limited to no ability to exercise influence over the operations on the Royalty Properties or the associated operating or capital costs, which could adversely affect the Company's financial performance. The Company's revenues, which are derived from the Royalty Properties operated by third parties, depend upon a number of factors, most of which are outside of the Company's control. Such factors include: the extent of exploration on and development of the Royalty Properties; the timing and amount of capital expenditures on those properties; the operator's expertise, production practices and financial resources; the approval of other participants; the selection of technology; risk management; compliance by third party lessees and/or operators with licence or lease terms relating to the Royalty Properties; and environmental compliance and remediation practices. While the Company actively pursues additional leasing and royalty arrangements with lessees and/or operators, there is no guarantee that the Company will be successful in securing such third parties for all or the majority of the Royalty Properties. Further, for Royalty Properties or formations that are not held by production at the end of the primary term, there can be no assurance that the Company will be able to re-lease such properties or formations or, if it is able to re-lease such properties or formations, that the lease terms and rates will be as favourable to the Company.

The third-party exploration and production companies involved with the Royalty Properties may manage or participate in a wide variety of projects in the conduct of their business, which may result in such third parties diverting capital, development activity and expertise away from the Royalty Properties. In addition, third party exploration and production companies involved in the Royalty Properties may defer or cancel capital projects in a low commodity price environment. The deferral or cancellation of development or capital projects conducted on the Royalty Properties may delay or reduce expected revenues from operations conducted by third parties on the Royalty Properties, which, in turn, would result in a reduction of the Company's revenues. The ability of these third parties to execute projects and market oil and natural gas from the Royalty Properties depends upon numerous factors beyond such third parties' and the Company's control, including the risk factors set out below. Because of these factors, these third parties could be unable to execute projects on the Royalty Properties on time, on budget, or at all, and may be unable to produce and market the oil and natural gas from the Royalty Properties effectively, all of which would result in a reduction of the Company's associated revenues.

In addition, due to the current low and volatile commodity prices, many companies, including companies that are lessees on the Fee Lands or working interest owners on the Royalty Properties, may be in financial difficulty, which could affect their ability to fund and pursue capital expenditures on such lands. Continued volatile commodity prices may also result in companies choosing to defer capital spending or shutting-in existing production. Any reduction in the drilling and production from lands in which the Company has a royalty interest will negatively affect the Company's cash flows and financial results.

Further, any financial difficulty of companies who are lessees on the Fee Lands or working interest owners on the Royalty Properties may affect the Company's ability to collect royalty payments especially if such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy, insolvency or creditor protection.

Third Party Exploration, Development and Production Risks

The Company's future performance may be affected by the financial, operational, environmental and safety risks associated with the exploration, development and production of oil and natural gas.

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to enter into lease and royalty arrangements with exploration and production companies and promote the exploration for and development and commercial production of crude oil and natural gas on the Company's properties by these lessees, as well as to acquire additional crude oil and natural gas assets to contribute to additional crude oil, natural gas and NGL reserves. A future increase in the Company's reserves will also depend on the ability of the Company to encourage further exploration on and development of the Royalty Properties by third parties. Without the continual addition of new reserves, the Company's reserves and related royalty revenue stream will decline over time as the lessees produce from such reserves. There is no assurance that the Company will be able to continue to find satisfactory third-party exploration and production companies to participate on the Royalty Properties or to otherwise acquire additional crude oil and natural gas assets to contribute additional reserves. Moreover, management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that these lessees will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration on the Royalty Properties 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 to a third party 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, which may result in decreased activities on the Royalty Properties by third parties and therefore less revenue to the Company.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations of third parties on the Royalty Properties and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents and the shutting-in of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect a third party's production from the Royalty Properties, which may reduce the Company's revenue.

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

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on third party's production from the Royalty Properties, which may reduce the Company's revenue.

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

Additional Capital and Funding Requirements at Onion Lake and Lindbergh

The Onion Lake and Lindbergh Projects will require additional financing, which may not be available.

The exploration, development, construction of facilities and ancillary matters related to oil and gas operations, and the acquired Onion Lake project and Lindbergh Project and oil sands or SAGD projects specifically, require substantial capital and the Company expects the operators of such projects or their successors will require additional financing to maintain and expand the projects. Failure to obtain sufficient financing may result in delaying or indefinite postponement of exploration, development or production on any or all of the project lands or even a loss of property interest. There can be no assurance that additional capital or other types of financing will be available if needed or that, if available, will be on satisfactory terms. See also "*Risk Factors - No Control over Operations on GORR Projects, and specifically at Onion Lake and Lindbergh*".

No Control over Operations on GORR Projects, and specifically at Onion Lake and Lindbergh

The Company does not control operations on its GORR projects.

The Company has purchased several GORR Interests, including the acquired royalties at Onion Lake and Lindbergh, which are directly correlated to the operational results of oil and gas operations and hydrocarbons produced therefrom. The Company is not directly involved in the working interest ownership or operation of the Lindbergh Project or Onion Lake project and has no contractual rights relating to the operation of such projects. The working interest owners and operators of oil and gas leases and licenses will generally have the power to determine the manner in which the relevant properties subject to a royalty interest, including a GORR Interest, are exploited and developed, including decisions to expand, advance, continue, reduce, suspend or discontinue production from a property. The interests of the Company and the operators of the Onion Lake project and Lindbergh Project may not always be aligned. As a result, the royalty share of production and associated cash flows of the Company are dependent upon the activities of the operators as it relates to such projects, which creates the risk that at any time the such operator may: (i) have business interests or targets that are inconsistent with those of the Company; (ii) take action contrary to the Company's policies or objectives; (iii) be unable or unwilling to fulfill their obligations under their agreements with the Company; or (iv) experience financial, operational or other difficulties, including insolvency, which could limit the operators ability to continue operations and further develop such projects. At any time, the operator may decide to suspend or discontinue operations, including if the costs to operate a project exceed the revenues from operations. The Company will not be entitled to any compensation if such operations are shut down, suspended or discontinued on a temporary or permanent basis. There can be no assurance that the production from the Onion Lake project or the Lindbergh Project will ultimately meet forecasts or targets. In addition, payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues. The payments pursuant to GORR Interests are calculated by the operator based on reported production and calculations of the Company's payments are subject to, and dependent upon, the adequacy and accuracy of the operators' production and accounting functions. Failure to receive payments under the GORR Interests to which the Company is entitled may have a material adverse effect on the Company and the dividend declared and paid by the Company. In addition, the Company must rely on the accuracy and timeliness of the public disclosure and other information it receives from the operator, and uses such information, including production estimates, in its analyses, forecasts and assessments relating to its own business. If the information provided by the operator to the Company contains material inaccuracies or omissions, the Company's ability to accurately forecast or achieve its stated objectives may be materially impaired.

Third Party Credit Risk

The Company is exposed to credit risk of third parties on the Royalty Properties.

The Company may be exposed to third party credit risk through its royalty and contractual arrangements with the third parties on the Royalty Properties, including operators of the properties, marketers of its crude oil and natural gas take-in-kind volumes, if any, and other industry participants. In the event such entities fail to meet their royalty, contractual or financial obligations to the Company, such failures could materially adversely affect the Company's business and financial condition. Further, poor credit conditions may impact a third party's ability to fund the development and capital programs conducted on the Royalty Properties, which in turn could result in a reduction of the Company's revenues. 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, it could result in the Company being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Company's business and financial condition. See "*Risk Factors – Dependence on Lessees and/or Operations*" and "*Risk Factors – Weakness in the Oil and Natural Gas Industry*".

Prices, Markets and Marketing

Various factors may adversely impact the marketability of oil and natural gas, affecting net production revenue, production volumes and development and exploration activities on the Royalty Properties.

Numerous factors beyond the Company's control do, and will continue to, affect the marketability and price of crude oil and natural gas anticipated to be produced from, or discovered on, the Royalty Properties. The ability to market oil and natural gas from the Royalty Properties may depend upon the ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the reserves on the Royalty Properties are from pipelines, railway lines, processing and storage facilities; operation problems affecting pipelines, railway lines and facilities; and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the lessees and operators of the Royalty Properties, which, in turn, could materially adversely affect the Company.

Prices for crude oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC and other oil and natural gas exporting nations, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for crude oil and natural gas are also subject to the availability of foreign markets and the ability to access such markets. A material decline in prices or a continued low crude oil and natural gas price environment could result in a reduction of the Company's anticipated net production revenue associated with the Royalty Properties. The economics of producing from some wells may change because of lower prices, which could result in reduced production of petroleum or natural gas and a reduction in the volumes of the reserves associated with the Royalty Properties. Lessees on the Royalty Properties may also elect, pursuant to the terms of the leases, during the primary term not to produce from certain wells at lower prices, which, in turn, would reduce the Company's revenues.

All of these factors could result in a material decrease in the Company's expected royalty revenue and a reduction in future oil and natural gas exploration, development and production activities. Any substantial and extended decline in or continued low crude oil and natural gas prices would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows and may have a material adverse effect on the Company's business and financial condition.

Crude oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply of and the demand for these commodities due to concerns of oversupply, the current state of the world economies, increased growth of shale oil production in the United States, OPEC actions, political uncertainties sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile crude oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and development activities and often cause disruption in the acquisition, divestiture or leasing of crude oil and natural gas producing properties, as buyers, sellers, lessors and lessees have difficulty agreeing on the value or terms of such arrangements. Price volatility also makes it difficult to budget for and project the return on potential acquisitions, divestitures or leasing opportunities.

See "*Risk Factors - Weakness in the Oil and Natural Gas Industry*".

Gathering and Processing Facilities, Pipeline Systems and Rail

Lack of capacity and/or regulatory constrains on gathering and processing facilities, pipeline systems and railway lines may have a negative impact on third parties' ability to produce and sell its oil and natural gas, which may affect the Company's business and financial condition.

The products produced from the Royalty Properties must be delivered through gathering, processing and pipeline systems, none of which are owned by the Company and some of which are not owned by the third parties active on the Royalty Properties, and in certain circumstances, by rail. The amount of oil and natural gas produced and sold from the Royalty Properties is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in an inability to realize the full economic potential of the Royalty Properties. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and natural gas to market. 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 shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect third parties' production and operations which may have a material adverse effect on the Company's business and financial condition. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, including remedial work on certain pipeline sections, as well as any delays or uncertainty in constructing new infrastructure systems and facilities, could harm the ability of third parties to develop and produce from the Royalty Properties and, in turn, the Company's business and financial condition. In addition, the federal government has signalled that it plans to review the National Energy Board approval process for large federally regulated projects. This may cause the timeframe for project approvals to increase for current and future applications.

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 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.

The production from the Royalty Properties is processed through facilities owned by third parties over which the Company, and in certain instances, the third parties on the Royalty Properties, have no control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse affect the ability of the third parties to process production from the Royalty Properties and to deliver the same for sale, which, in turn, would indirectly reduce the Company's revenues.

For royalty payments taken-in-kind by the Company, if any, the ability of the Company or a third-party marketer to successfully market in-kind oil and natural gas products may depend, in part, on the Company's or the third-party marketer's ability to acquire space on pipelines that deliver crude oil and natural gas to commercial markets. Deliverability uncertainties related to the distance the Company's reserves are to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities, as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and other aspects of the oil and natural gas industry may also affect the Company.

Availability of Drilling Equipment and Access

Restrictions on the availability of and access to drilling equipment may impede third parties' exploration and development activities, which may affect the Company's business and financial condition.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel for the third parties operating on the Royalty Properties and may delay such exploration and development activities, which, in turn, could materially adversely affect the Company's business and financial condition.

Weakness in the Oil and Natural Gas Industry

Weakness and volatility in the market conditions for the oil and natural gas industry may affect the value of the reserves on the Royalty Properties, restrict their cash flow and their ability to access capital to fund the development of the Royalty Properties, which may affect the Company.

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by the Organization of the Petroleum Exporting Countries (*OPEC*), slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in the case of Alberta, at the provincial level, and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in western Canada has led to additional downward price pressure on crude oil and natural gas produced in western Canada and uncertainty and reduced confidence in the oil and natural gas industry in western Canada. Lower commodity prices may also affect the volume and value of the Company's reserves rendering certain reserves uneconomic for development by lessees on the Fee Lands and operators and working interest owners on the Royalty Properties. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, lessees and working interest owners on the Royalty Properties and operators and working interest owners' cash flow resulting in reduced capital expenditure budgets and in turn, adversely affecting the royalty revenue received by the Company. The third parties operating on the Royalty Properties may not be able to replace their production with additional reserves which may result in the Company's production and reserves being reduced on a year over year basis. In addition to possibly resulting in a decrease in the value of the economically recoverable reserves from the Royalty Properties, lower commodity prices may also result in a decrease in the value of the infrastructure and facilities on such Royalty Properties, all of which could also have the effect of requiring a write down of the carrying value of the Company's oil and natural gas assets on its balance sheet and the recognition of an impairment charge in its income statement. Given the current market conditions, the Company may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and/or highly dilutive terms.

Political Uncertainty

The Company's business may be adversely affected by recent political and social events and decisions made in the United States, Europe and elsewhere.

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 2016 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 NAFTA, 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 how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including the Company.

In addition to the political disruption in the United States, the citizens of the United Kingdom 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 the Company’s ability to market its products internationally, increase costs for goods and services required for third party lessees' operations, reduce their access to skilled labour and as a result, negatively impact the Company's business, operations, financial conditions and the market value of the Common Shares.

Geopolitical Risks

Global political events may adversely affect commodity prices which in turn affect the Company's royalty revenue.

Political events throughout the world that cause disruptions in the supply of oil and natural gas continue to affect the marketability and price of crude oil and natural gas. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices, which could, in turn, result in a reduction of the Company's royalty revenue.

Eco-Terrorism Risks

The Royalty Properties and nearby facilities may be subject to terrorist attack.

The Royalty Properties and facilities located in proximity to the Royalty Properties could be subject to a terrorist attack, which could materially adversely affect the Company's business and financial condition. The Company does not have insurance to protect against the risk from terrorism.

Alternatives to and Changing Demand for Petroleum Products

Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Company's business and financial condition.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and renewable energy generation devices could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes could materially adversely affect the Company's business and financial condition by decreasing the Company's royalty revenues and decreasing the value of its assets.

Seasonality and Extreme Weather Conditions

Oil and natural gas operations are subject to seasonal and extreme weather conditions and significant operational delays on the Royalty Properties may be experienced as a result.

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 potentially reducing activity levels on the Royalty Properties. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some production on the Royalty Properties if not otherwise tied-in. Also, certain oil and natural gas producing properties 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 access to the Royalty Properties and cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and also to volatility in commodity prices as the demand for natural gas rises during cold winter months and hot summer months.

Regulatory

Modification to current or implementation of additional regulations may reduce the demand for oil and natural gas and/or increase costs and/or delay planned operations on the Royalty Properties.

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations, including potential expropriation of fee simple mineral title lands, changes to royalty regimes or the calculation of production and mineral taxes, may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase costs or make certain projects on the Company's properties uneconomic, which could materially adversely affect the Company's business and financial condition. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and natural gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact oil and natural gas operations and may affect the Company's royalty revenues. See "*Industry Conditions – Climate Change Regulations*".

In order to conduct oil and natural gas operations, the Company will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that the Company will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* could negatively affect the Company's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

Environmental

Compliance with environmental regulations requires the dedication of a portion of the financial and operational resources of the lessees and/or operators of the Royalty Properties.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural 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.

As a royalty interest holder, the Company believes it has minimal or no direct exposure to environmental claims and regulation or the associated costs. However, such matters will directly impact the lessees and/or operators of the Royalty Properties. Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties on such lessees or operators, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the lessee or operators of the Royalty Properties to incur costs to remedy such discharge. The Company relies on the lessee or operators of the Royalty Properties to be in material compliance with current applicable environmental legislation; however, 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 associated with the Royalty Properties or otherwise have a material adverse effect on the Company's business and financial condition.

Liability Management

Liability management programs enacted by regulators in the western provinces may prevent or interfere with a third party's ability to acquire properties or require a substantial cash deposit with the regulator, which may affect the Company's business and financial condition.

Alberta, Saskatchewan and British Columbia have 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 regulatory obligations. These programs 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 generally required. Changes to the required ratio of third-party operators deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the security that must be posted by such third parties, which could impact the availability of capital to be spent by them which could in turn materially adversely affect the Company's business and financial condition. In addition, the liability management regime may prevent or interfere with a third party's 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, found an operational conflict between the BIA and the AER's abandonment and reclamation powers when the licensee is insolvent, which was affirmed by a majority of the Alberta Court of Appeal, and has been appealed by the AER to the Supreme Court of Canada for final determination. In response to the decision, the AER issued interim rules to administer the liability management program until the Government of Alberta can develop new regulatory measures to adequately address environmental liabilities. There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions.

See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Royalty Regimes

Changes to royalty regimes may negatively impact the Company's earnings.

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of third-party lessees of Crown lands. An increase in royalties would reduce the Company's earnings and could make future capital investments by third parties on the Crown lands less economic. 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*".

Climate Change

Compliance with GHG emissions regulations may result in increased operational costs to third parties, which may indirectly affect the Company's business and financial condition.

Operations and activities associated with the Royalty Properties emit GHGs which may require parties leasing and/or operating the Royalty Properties or certain of the Company's assets to comply with greenhouse gas emissions legislation at the provincial and 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 UNFCC and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Although the Company's business does not include any facilities, facilities that may, in the future, be located on the Royalty Properties may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. 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 GHG and resulting requirements, it is expected that current and future climate change regulations will have the affect of increasing the Company's operating expenses and in the long-term reducing the demand for crude oil and natural gas production resulting in a decrease in the Company's profitability and a reduction in the value of its assets or asset write-offs. See "*Industry Conditions - Climate Change Regulation*".

Hydraulic Fracturing

Implementation of new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes for third parties, adversely affecting the Company's financial position.

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 oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the 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 on the Royalty Properties. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that is ultimately produced from the reserves associated with the Royalty Properties and, therefore, could materially adversely affect the Company's business, financial condition, results of operations and prospects.

Title to Assets

Defects in title to the Company's properties may result in a financial loss.

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise to defeat the Company's claim. The actual interest of the Company in the Royalty Properties may, therefore, vary from the records previously maintained by the prior owners. If a title defect does exist, it is possible that the Company may lose all or a portion of the properties to which the title defect relates, which could materially adversely affect the Company's business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the Royalty Properties that, if successful or made into law, could impair our royalty interests and result in a reduction of the revenue received by the Company.

Other Title Risks, including those applicable to Gross Overriding Royalties

Defects in title to the GORR Interests may result in a financial loss.

The majority of our GORR Interests attach to licenses and leases and working interests in licenses and leases. If 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 thereby terminating our GORR Interest. 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. Furthermore, there may be valid challenges to title or proposed legislative changes which affect title to the leases and licenses to which GORR Interests attach that, if successful or made into law, could impair our royalty interests and result in a reduction of the revenue received by us.

Litigation and Aboriginal Claims

The Company may be involved in litigation in the course of its normal operations and the outcome of the litigation may adversely affect the Company and its reputation and Aboriginal claims may affect the Company.

In the normal course of the Company's activities, it 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, relating to property damage, personal injury, property tax, land rights, royalty rights, access rights, the environment and lease and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty, such proceedings may be determined adversely to the Company and any indemnity from Encana, the CNRL Parties or other third parties in respect of any loss suffered by the Company as a result of such proceedings may not be sufficient, and, as a result, could materially adversely affect the Company's business, financial condition, results of operations and prospects. Even if the Company prevails in any such legal proceeding, the proceeding could be costly and time consuming and may divert the attention of management and key personnel away from business operations, which may materially adversely affect the Company's financial condition.

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada, including in the Provinces of British Columbia, Alberta, Saskatchewan and Manitoba. In particular, certain aboriginal groups have challenged title to lands near the Fee Lands and the GORR Lands. If such claims arose in relation to the Fee Lands and GORR Lands, and such claims were successful, it could materially adversely affect the Company's business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The anticipated benefits of acquisitions may not be achieved and the Company may dispose of certain assets for less than their carrying value on the financial statements as a result of weak market conditions.

While management is focused on encouraging third parties to develop the Royalty Properties, the Company considers acquisitions and dispositions of certain petroleum or natural gas assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. The Company may also enter into other industry related activities or new geographical areas or acquire different energy-related assets that may result in unexpected or significantly increased risk to the Company, which could materially adversely affect the Company's business, financial condition, results of operations and prospects. Additionally, management will continually assess the value and contribution of the various properties and assets within its portfolio. In this regard, certain assets may be periodically disposed of so the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such assets, certain assets of the Company may realize less on disposition than what the market may expect for such disposition or their carrying value on the financial statements of the Company.

Management of Growth and Integration

The Company may not be able to effectively manage the growth of its business.

The Company may be subject to both transition and growth-related risks, including capacity constraints and pressure on its internal systems and controls. The historical financial and operating results of the assets acquired including assets acquired pursuant to the Encana Royalty Acquisition, the Range Royalty Acquisition and the CNRL Royalty Acquisition while they were under the management of Encana, Range Royalty and CNRL, respectively, may not be indicative of future results. In particular, the Company is responsible for managing a substantial number of land and title documents and related accounting functions that require significant employee resources. The ability of the Company to manage future growth and integration of additional lands, leases and acquisitions effectively requires it to continue to implement and improve financial and land systems and to expand, train and manage its employee base. The inability of the Company to deal with this integration and growth may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Reserves Estimates

The estimated proved and proved plus probable reserves are based on numerous factors and assumptions which may prove incorrect and which may affect the Company.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserves and associated cash flow information set forth in this AIF are estimates only. Generally, estimates of economically recoverable crude oil, natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as: historical production from the properties; production rates; ultimate reserve recovery; timing and amount of capital expenditures by the working interest owners thereon; marketability of oil and natural gas; royalty rates (which, in the case of the Company, generally consist of the royalties to be paid to the Company); and the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results.

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

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

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

Actual production and cash flows derived from the Company's crude oil, natural gas and NGL reserves will vary from the estimates contained in the GLJ Report and such variations could be material. The reserves evaluation is based in part on the assumed success of activities undertaken on the Royalty Properties in future years. The reserves and estimated cash flows to be derived therefrom and contained in the GLJ Report will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The GLJ Report is effective as of December 31, 2017, with a preparation date of January 23, 2018, and, except as may be specifically stated or required by applicable securities laws, has not been updated and, therefore, does not reflect changes in reserves since that date.

Market Price of Common Shares

The trading price of the Common Shares may be adversely affected by factors related and unrelated to the oil and natural gas industry.

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 the Company's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and natural gas market. In certain jurisdictions institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Company's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

Negative Impact of Additional Sales or Issuances of Common Shares

The Company may issue additional Common Shares, diluting current shareholders.

The Board may issue an unlimited number of Common Shares without any vote or action by the shareholders, subject to the rules of any stock exchange on which the Company's securities may be listed from time to time. The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities. If the Company issues any additional equity, the percentage ownership of existing shareholders will be reduced and diluted and the price of the Common Shares could decline.

Capital and Additional Funding Requirements

The Company may require additional financing from time to time to fund the acquisition of additional oil and natural gas assets and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility.

The Company's cash flow from the Royalty Properties may not be sufficient to fund its ongoing activities at all times, and from time to time the Company may require additional financing, which may include financing for the acquisition of additional oil and natural gas assets. Future capital and other expenditures will be financed out of cash flow from royalty revenues, borrowings and possible future equity issuances, and the Company's ability to do so will be dependent on, among other factors: the overall state of the capital markets; commodity prices; the Company's credit rating (if applicable); interest rates; tax burden due to current and future tax laws; and investor appetite for investments in the energy industry and the Company's securities in particular. Failure to obtain financing on a timely basis could cause the Company to miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, the Company may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access additional financing.

There can be no assurance that debt or equity financing, or cash flow generated by operations, will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. Alternatively, any available financing may be highly dilutive to existing shareholders. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Company's access to additional financing may be affected. The inability of the Company to access sufficient capital for its operations could cause the Company to, amongst other things, miss certain acquisition opportunities, and may materially adversely affect the Company's financial condition.

In addition, the future development of the Royalty Properties by third parties may require additional financing and there are no assurances that such financing will be available, and, if available, will be available upon acceptable terms to such third parties. Failure to obtain any financing necessary for such third parties' capital expenditure plans may result in a delay in development of the Royalty Properties.

Cash Dividend Payments are not Guaranteed

The amount of and frequency at which future cash dividends are paid may vary and there is no assurance that the Company will pay dividends in the future.

The payment of dividends by the Company is not guaranteed and could fluctuate with the performance of the Company or as a result of market conditions. The Board has the discretion to determine the amount of dividends, if any, to be declared and paid to shareholders. The Company may alter its dividend policy at any time and the payment of dividends will depend on, among other things, changes in commodity prices; financial condition; current and expected future levels of earnings; liquidity requirements; market opportunities; income taxes; debt repayments; legal, regulatory and contractual constraints; tax laws; and other relevant factors. The Credit Facility may prohibit the Company from paying dividends at any time at which a default or event of default has occurred and is continuing, or if a default or event of default would exist as a result of paying the dividend.

Over time, the Company's capital and other cash needs may change significantly from its current needs, which could affect whether the Company pays dividends and the amount of dividends, if any, it may pay in the future. If the Company continues to pay dividends at the current levels, it may not retain a sufficient amount of cash to finance external growth opportunities, meet any large unanticipated liquidity requirements or fund its activities in the event of a significant business downturn. The Board may amend, revoke or suspend the Company's dividend policy at any time. A decline in the market price or liquidity, or both, of the Common Shares could result if the Company reduces or eliminates the payment of dividends, which could result in losses to shareholders. Further, the market value of the Common Shares may deteriorate if cash dividends are reduced or suspended.

Foreign Exchange Risk on Dividends

Variations in foreign exchange rates may affect the amount of cash dividends received by shareholders who receive dividends in currencies other than Canadian dollars.

The Company's cash dividends are declared in Canadian dollars and may be converted in certain instances to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, non-resident shareholders, and shareholders who calculate their return in currencies other than the Canadian dollar, are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the dividend will be reduced when converted to their home currency.

Additional Taxation Applicable to Dividends Paid to Non-Residents

Non-resident shareholders are required to pay additional taxes on their dividends.

Cash dividends paid to a non-resident of Canada on Common Shares are subject to Canadian withholding tax at a rate of 25% unless the rate is reduced under the provisions of an applicable double taxation treaty. Where a non-resident is a United States resident entitled to benefits of the Canada – United States Income Tax Convention, 1980 and is the beneficial owner of the dividends then the rate of Canadian withholding tax is generally reduced to 15%.

Variations in Foreign Exchange Rates and Interest Rates

Variations in foreign exchange rates and interest rates could adversely affect the Company's financial condition.

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, could consequently affect the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar may indirectly affect the Company's revenues, as revenues received by Canadian producers and, similarly, royalties payable to the Company, could decrease. Future variations in Canadian/United States exchange rates may accordingly affect the future value of the Company's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively impact the price the Company and the lessees and/or operators of Royalty Properties receive for oil and natural gas production it could also result in an increase in the price of certain goods used by lessees and operators of the Royalty Properties in their operation which may materially adversely affect on the Company's financial condition.

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

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, resulting in a reduced amount available to fund its activities and the cash available to pay dividends, and could negatively impact the market price of the Common Shares.

Hedging

Hedging activities may expose the Company to the risk of financial loss and counter-party risk.

The Company may enter into hedging arrangements to fix interest rates applicable to the Company's debt. However, if interest rates decrease as compared to the interest rate fixed by the Company, the Company will not benefit from the lower interest rate.

The Company may enter into agreements to fix the commodity prices for its royalty volumes, if any, in order to offset the risk of revenue losses. Such hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

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

Further, if commodity prices increase compared to the prices fixed by the Company, the Company will not benefit from such higher prices.

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

Income Taxes

Taxation authorities may reassess the Company's tax returns.

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

The Company files all required income tax returns in order to be in full compliance with the provisions of the Tax Act 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 the Company, such reassessment may have an impact on current taxes payable and deferred tax liabilities.

Issuance of Debt

Increased debt levels may impair the Company's ability to borrow additional capital on a timely basis to fund opportunities as they arise.

From time to time, the Company may finance its activities (including potential future oil and natural gas royalty asset acquisitions) in whole or in part with debt, which may increase the Company's debt levels above industry standards for peers of similar size. Additional debt financing may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time could impair the Company's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Credit Facility Arrangements

Failing to comply with covenants under the Company's credit facility could result in restricted access to capital or being required to repay all amounts owing thereunder.

Pursuant to the terms and conditions of the Credit Facility, the Company is required to comply with customary positive and negative covenants thereunder and in the event that the Company does not comply with these covenants, the Company's access to capital could be restricted or repayment could be required. Events beyond the Company's control may contribute to the failure of the Company to comply with such covenants. A failure to comply with any of the covenants could result in an event of default which, if not cured or waived, would permit acceleration of the indebtedness pursuant to the Credit Facility and would prevent dividends from being paid to shareholders. The acceleration of the Company's indebtedness under the Credit Facility may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facility will impose certain operating and financial restrictions on the Company that include restrictions on the payment of dividends, limitations on liens, entering into disposition of assets or amalgamations and restrictions on speculative hedging, among others. Even if the Company is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Company.

If the Company's lenders require repayment of all or portion of the amounts outstanding under the Credit Facility for any reason, including for a default of a covenant, there is no certainty that the Company would be in a position to make such repayment. Even if the Company is able to obtain new financing in order to make any required repayment under the Credit Facility, it may not be on commercially reasonable terms or terms that are acceptable to the Company. If the Company is unable to repay amounts owing under the Credit Facility, the lenders under the Credit Facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Reliance on Key Personnel

Loss of key personnel would negatively impact the Company's operations.

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key personnel insurance in effect for the Company. The contributions of the existing management team to the immediate and near-term operations of the Company are likely to be of central importance. In addition, the competition for qualified personnel in Alberta, and in particular, the oil and natural gas industry, is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

Competition

The Company competes with other entities to encourage the acquisition and development of Royalty Properties, some of which have greater financial resources, staff or political influence.

The oil and natural gas industry is highly competitive in all of its phases. The Company competes with numerous other entities to encourage third party development of the Royalty Properties and to acquire additional oil and natural gas assets. The Company's competitors include other fee simple mineral title owners, exploration and production companies and the Provincial and Federal Crown, as the owners of the significant majority of mineral rights in western Canada, any of whom may have more financial resources, staff or political influence than those of the Company. The Company's ability to increase its reserves and revenue streams in the future will depend not only on its ability to promote development of the Royalty Properties, but also on its ability to select other suitable producing properties or prospects for third party exploratory drilling and further development.

Conflicts of Interest

Conflicts of interest may arise for the Company's directors and officers who are also involved with other industry participants.

Certain members of the Board and management are also, or may in the future be, directors or officers of other oil and natural gas companies, that may compete or be counterparties to agreements with the Company, and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Company disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

Breach of Confidentiality

Breach of confidentiality by a third party could impact the Company's competitive advantage or put it at risk of litigation.

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to the business, operations or affairs of the Company. Although confidentiality agreements are generally signed by third parties prior to the disclosure of any confidential information by the Company, a breach could put the Company at competitive risk and may cause significant damage to its business. The harm to the Company's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable solely in monetary damages. There is no assurance that, in the event of a breach of confidentiality, the Company 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.

Information Technology Systems and Cyber-Security

Breaches of the Company's cyber-security and loss of, or access to, electronic data may adversely impact its operations and financial position.

The Company has become increasingly dependent upon the availability, capacity, reliability and security of its information technology infrastructure and its ability to expand and continually update this infrastructure, to conduct daily operations. The Company depends on various information technology systems to estimate reserve quantities, process and record financial data, manage its land base, manage financial resources, analyze seismic information, administer its contracts with its operators and lessees and communicate with employees and third-party operators.

Further, the Company is subject to a variety of information technology and system risks as a part of its normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's 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 its business activities or its competitive position. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If the Company becomes a victim to a cyber phishing attack it could result in a loss or theft of the Company's financial resources or critical data and information or could result in a loss of control of the Company's technological infrastructure or financial resources. The Company applies technical and process controls in line with industry-accepted standards to protect its information assets and systems; however, these controls may not adequately prevent cyber-security breaches. 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. 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 the Company's business, financial condition, results of operations and prospects.

Access to Our Offices and Properties

Employees must be able to physically access our offices and properties.

The Company's ability to carry on its business is dependent upon the ability of its employees to physically access its offices and properties. If access to the Company's office and properties is interrupted then the Company's ability to administer and manage its business may be materially and adversely affected.

Limited Ability of Residents in the United States to Enforce Civil Remedies

Shareholders in the United States have a limited ability to enforce civil remedies against the Company in Canada.

The Company is a corporation formed under the laws of Alberta, Canada and has its principal place of business in Canada. All of our directors and all of our officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all of our assets and all or a substantial portion of 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 judgments 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 the Company or against 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 judgments 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.

Forward-Looking Information

Forward-Looking Information may prove inaccurate.

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

Additional information on the risks, assumption and uncertainties are found under the heading "*Cautionary Statement Regarding Forward-Looking Information and Statements*" in this AIF.

Carbon Pricing Risk

Taxes on carbon emissions affect the demand for oil and natural gas.

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. See "*Industry Conditions – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the operating expenses of oil and natural gas companies, each of which may have a material adverse effect on the Company's revenue from the Royalty Properties. Further, the imposition of carbon taxes puts the Company at a disadvantage with its counterparts who operate in jurisdictions where there are less costly carbon regulations.

Insurance

Not all business risks are insurable and the occurrence of an uninsurable event may have an effect on the Company.

Although the Company maintains insurance in accordance with industry standards to address certain risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Expiration of Licenses and Leases

The lessees of the Royalty Interests may fail to meet the requirements of a licence or lease, causing its termination or expiry.

Certain of the properties that the Company holds the Royalty Interests in are tied to licences and leases and working interests in licences and leases. If the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of these licences or leases or the working interests relating to a licence or lease may impair certain of the Royalty Interests and in turn may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Reputational Risk

The Company relies on its reputation to continue its operations and to attract and retain investors and employees.

Any environmental damage, loss of life, injury or damage to property caused by the operations on the Royalty Properties could damage the reputation of the lessees or operators of the Royalty Properties and, in turn, the Company, in the areas in which the Company holds Royalty Properties. Negative sentiment towards any of the lessees or operators of the Royalty Properties could result in a lack of willingness of municipal authorities being willing to grant the necessary licenses or permits for those lessees or operators to operate their business and in residents in the areas where such lessees or operators are doing business opposing further operations in the area by such lessees or operators, which could negatively impact the Company's revenues. The Company's reputation could be affected by actions and activities of other corporations operating in the oil and natural gas industry, over which the Company has no control. If the

Company, either directly or indirectly, develops a reputation of having an unsafe work site it may impact the ability of the Company to attract and retain the necessary skilled employees and consultants to operate its business. In addition, environmental damage, loss of life, injury or damage to property caused indirectly by the Company's operations could result in negative investor sentiment towards the Company, which may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Changing Investor Sentiment

Changing investor sentiment towards the oil and natural gas industry may impact the Company's access to, and cost of, capital.

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and gas properties or companies tied to oil and gas or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can be costly and require a significant time commitment from the Board, management and employees of the Company. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in the Company or not investing in the Company at all. Any reduction in the investor base interested or willing to invest in the oil and natural gas industry, and more specifically, the Company, may result in limiting the Company's access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of the Company includes an unlimited number of Common Shares and an unlimited number of preferred shares issuable in series. As of February 26, 2018, 235,462,341 Common Shares and nil preferred shares were issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions which are attached to the Common Shares and preferred shares.

Common Shares

The rights, privileges, restrictions and conditions attaching to the Common Shares are set forth below.

Voting Rights

The holders of the Common Shares are entitled to one vote in respect of each Common Share held at all meetings of shareholders, except meetings at which only holders of a specified class of shares have the right to vote.

Dividends

Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Company, holders of Common Shares are entitled to receive any dividend declared by the Company on the Common Shares.

Rights upon Dissolution

Subject to the rights, privileges, restrictions and conditions attaching to any other class or series of shares of the Company, holders of Common Shares are entitled to receive the remaining property of the Company upon dissolution.

Preferred Shares

The Board may issue preferred shares at any time and from time to time in one or more series, and shall determine the rights, privileges, restrictions and conditions attached to each series of preferred shares before the issue of such series.

Dividends

Preferred shares may be entitled to preference over the Common Shares and any other shares of the Company ranking junior to the preferred shares with respect to payment of dividends.

Rights upon Dissolution

Preferred shares may be entitled to preference over the Common Shares and any other shares of the Company ranking junior to the preferred shares with respect to distribution of assets in the event of liquidation, dissolution or winding-up of the Company, whether voluntary or involuntary.

MARKET FOR SECURITIES

Trading Volume and Price

The Common Shares are listed and trade on the TSX under the symbol "PSK". The following table sets forth the high and low trading prices and the aggregate trading volume of the Common Shares on the TSX for the periods indicated. During 2017, the Company purchased, for cancellation, 1,402,300 Common Shares under its previously filed normal course issuer bid.

Toronto Stock Exchange

	High ($/Common Share)	Low ($/Common Share)	Volume Traded
2017			
January	33.36	29.84	10,050,757
February	31.08	28.52	13,075,445
March	31.21	27.10	14,746,841
April	29.88	28.01	8,498,143
May	30.41	28.01	7,398,299
June	30.06	27.74	7,625,714
July	31.50	27.55	7,277,217
August	31.40	27.44	8,141,807
September	33.21	28.90	11,005,456
October	34.81	30.50	11,566,359
November	35.90	31.69	10,675,770
December	34.32	31.07	9,056,565
2018			
January	33.23	30.11	9,416,185
February (1-23)	30.76	28.03	7,007,902

DIVIDENDS

The Board has established a dividend policy pursuant to which the Company pays a monthly dividend of $0.0625 per Common Share per month or $0.75 per Common Share on an annualized basis. On February 26, 2018, PrairieSky announced that the Board had approved and increased the dividend to $0.065 per Common Share per month or $0.78 per Common Share on an annualized basis, effective for the March 29, 2018 dividend record date which is expected to be paid on or about April 16, 2018. The Board reviews and determines the dividend rate annually after considering expected commodity prices, foreign exchange rates, economic conditions, production volumes, taxes payable, and PrairieSky's capacity to fund operating and investing opportunities. The dividend rate is established with the intent of absorbing short-term market volatility over several months. It also recognizes the intention of maintaining a strong financial position to take advantage of business development opportunities and withstand periods of commodity price volatility.

The dividends are paid monthly to shareholders of record as of the close of business on the last business day of each calendar month, with the 15th day (or next business day) of the following month being the corresponding payment date. Dividend payments are not guaranteed and the amount of cash to be distributed as dividends in the future may change. Any decision to pay dividends will be determined at the discretion of the Board after reviewing the overall dividend policy of the Company and after consideration of numerous factors including: (i) the earnings of the Company; (ii) financial requirements for the Company's operations; (iii) the satisfaction by the Company of liquidity and insolvency tests described in the ABCA; and (iv) any agreements relating to the Company's indebtedness that restrict the declaration and payment of dividends. The dividends paid on the Common Shares pursuant to the Company's dividend policy are designated as "eligible dividends" for Canadian income tax purposes, unless otherwise notified.

The cash dividends set forth in the table below have been paid by the Company to its shareholders in the months indicated.

Month of Dividend Payment Date	
2017	
January	$0.06000
February	$0.06000
March	$0.06000
April	$0.06250
May	$0.06250
June	$0.06250
July	$0.06250
August	$0.06250
September	$0.06250
October	$0.06250
November	$0.06250
December	$0.06250
2018	
January	$0.06250
February	$0.06250

The historical cash dividend payments described above may not be reflective of future dividend payments, and future dividend payments are not assumed or guaranteed.

Passive Foreign Investment Company

In consultation with its U.S. tax advisors, PrairieSky believes it may be classified as a passive foreign investment company (*PFIC*) under United States federal income tax principles. As such, dividends to taxable individual shareholders who are United States taxpayers should continue to be subject to the regimes of United States federal income taxation applicable to PFICs. Shareholders who are United States taxpayers should discuss with their tax advisors the reporting requirements with respect to owning shares in a PFIC. PrairieSky, in order to allow shareholders the ability to make a Qualified Electing Fund election, posts annually a PFIC Annual Information Statement on its website. Shareholders should contact their own tax advisors for information on correctly completing Form 8621. This information is not available from PrairieSky.

DIRECTORS AND EXECUTIVE OFFICERS

Board of Directors of PrairieSky

As at February 26, 2018, the Board is comprised of five individuals. The name, province of residence, position held and principal occupation of each director of PrairieSky are set out below.

Name, Province and Country of Residence	Principal Occupation	Director Since
James M. Estey(1)(2)(3)(4) Calgary, Alberta, Canada	Corporate Director	April 11, 2014
Margaret McKenzie(3)(4) Calgary, Alberta, Canada	Corporate Director	December 19, 2014
Andrew M. Phillips Calgary, Alberta, Canada	President & Chief Executive Officer of the Company	April 11, 2014
Sheldon B. Steeves(2)(3)(4) Calgary, Alberta, Canada	Corporate Director	April 11, 2014
Grant A. Zawalsky(2)(4) Calgary, Alberta, Canada	Managing Partner, Burnet, Duckworth & Palmer LLP	December 19, 2014

Notes:
(1) Chair of the Board.
(2) Member of the Governance and Compensation Committee. Mr. Estey is the Chair of the Governance and Compensation Committee.
(3) Member of the Audit Committee. Ms. McKenzie is the Chair of the Audit Committee.
(4) Member of the Reserves Committee. Mr. Steeves is the Chair of the Reserves Committee. Mr. Estey is an ex officio non-voting member of the Reserves Committee.

Executive Officers of PrairieSky

The following table sets forth the name, province of residence, position held and date of appointment of each of the executive officers of PrairieSky.

Name, Province and Country of Residence	Principal Occupation	Date of Appointment as an Officer
Andrew M. Phillips Calgary, Alberta, Canada	President & Chief Executive Officer of the Company	April 11, 2014
Cameron M. Proctor Calgary, Alberta, Canada	Chief Operating Officer of the Company	April 11, 2014
Pamela Kazeil Calgary, Alberta, Canada	Vice President, Finance & Chief Financial Officer of the Company	June 1, 2015

Name, Province and Country of Residence	Principal Occupation	Date of Appointment as an Officer
Michelle Radomski Calgary, Alberta, Canada	Vice President, Land of the Company	December 19, 2014

As at February 26, 2018, the directors and executive officers of PrairieSky, as a group, beneficially own or control, directly or indirectly, 2.4 million Common Shares or 1% of the issued and outstanding Common Shares.

Directors and Executive Officers Biographical Information

The following are brief profiles of each of the directors and executive officers of the Company, which include a description of their present occupation and their principal occupations for the past five years.

James M. Estey

Mr. Estey's principal occupation is as a Corporate Director. Mr. Estey is the retired Chairman of UBS Securities Canada Inc., a financial services company, and has more than 40 years of experience in financial markets. Mr. Estey joined Alfred Bunting and Company as an institutional equity salesperson in 1980 after working at A.E. Ames & Co. for seven years. In 1994, Mr. Estey became the head of the Canadian Equities business, and in 2002 Mr. Estey was appointed President & Chief Executive Officer of UBS Securities Canada Inc. In January 2008, Mr. Estey assumed the role of Chairman of UBS Securities Canada Inc. Mr. Estey is a director and Chairman of Gibson Energy Inc., a TSX-listed oil and natural gas service company, and a director of New Gold Inc., a mining company listed on the TSX and the New York Stock Exchange (*NYSE*). Mr. Estey also serves on the Advisory Board of the Edwards School of Business at the University of Saskatchewan.

Margaret McKenzie

Ms. McKenzie was formerly the Vice President, Finance and Chief Financial Officer of Range GP and prior thereto was Vice President, Finance and Chief Financial Officer of Profico Energy Management Ltd. (a private oil and natural gas company). Ms. McKenzie holds a Bachelor of Commerce degree (with distinction) from the University of Saskatchewan and has been a member of the Chartered Professional Accountants of Alberta since 1985. She obtained her ICD.D designation from the Institute of Corporate Directors in 2013. Ms. McKenzie is an experienced director and currently sits as a director of Bonavista Energy Corporation, a TSX-listed oil and natural gas company, Encana Corporation, a TSX and NYSE listed oil and natural gas company, and Inter Pipeline Ltd., a TSX listed petroleum transportation, storage and natural gas liquids extraction company.

Andrew M. Phillips

Mr. Phillips is the President and Chief Executive Officer of the Company and has over 15 years of experience in the oil and natural gas industry in the areas of exploration, geology, business development, asset evaluation and executive management. Prior to his appointment as President and Chief Executive Officer of the Company, Mr. Phillips was the President and Chief Executive Officer and a director of Home Quarter Resources Ltd. (*Home Quarter*), a private oil and natural gas company founded by Mr. Phillips in 2010 with producing properties and royalty interests in southwest Saskatchewan and Alberta. Home Quarter was successfully divested to a public oil and natural gas company in 2014. Prior thereto, Mr. Phillips was the Vice President, Exploration at Evolve Exploration Ltd., a private junior oil and natural gas company with assets in western Canada, and an exploration geologist at each of Profico Energy Management Ltd. and at Renaissance Energy Ltd., both of which were Canadian oil and natural gas exploration companies. Mr. Phillips holds a Bachelor of Science, Geology degree from the University of Calgary and is a member of the Association of Professional Engineers and Geoscientists of Alberta and the Canadian Society of Petroleum Geologists.

Sheldon B. Steeves

Mr. Steeves' principal occupation is as a Corporate Director. Mr. Steeves is a director of Enerplus Corporation and NuVista Energy Ltd., each of which is an oil and natural gas company listed on the TSX. From January 2001 until April 2012, Mr. Steeves was Chairman and Chief Executive Officer of Echoex Ltd., a private junior oil and natural gas company, and spent over 15 years at Renaissance Energy Ltd., a Canadian oil and gas exploration company, where he was appointed Chief Operating Officer & Executive Vice President in 1997. Mr. Steeves holds a Bachelor of Science degree in Geology from the University of Calgary and is a member of the Association of Professional Engineers and Geoscientists of Alberta, the Canadian Society of Petroleum Geologists and the American Association of Petroleum Geologists.

Grant A. Zawalsky

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 is an experienced director and currently sits on the board of directors of a number of private and public companies, including Whitecap Resources Inc., NuVista Energy Ltd. and Zargon Oil & Gas Ltd.

Cameron M. Proctor

Mr. Proctor is the Chief Operating Officer of the Company, as well as the Corporate Secretary of the Company, and has experience in the oil and natural gas industry managing several business units including legal, business development, regulatory, human resources, corporate governance, government and stakeholder relations, information technology and business services. From April 2014 to February 2015, Mr. Proctor was the Vice-President, Legal and Corporate Services of the Company. Prior to joining the Company, Mr. Proctor was the Executive Vice-President and Chief Legal Officer and a member of the board of directors of Sinopec Canada, working for Sinopec Canada and its predecessor companies since 2010, including as Vice President, General Counsel and Corporate Secretary of Daylight Energy Ltd. Prior thereto and since 2003, Mr. Proctor was a barrister and solicitor at Blake, Cassels & Graydon LLP, specializing in corporate, securities and mergers and acquisitions law. Mr. Proctor holds a Bachelor of Arts degree from the University of Victoria and a Bachelor of Laws from the University of Calgary.

Pamela Kazeil

Ms. Kazeil is the Vice President, Finance & Chief Financial Officer of the Company, and has significant experience in the oil and natural gas industry managing finance, accounting, treasury and tax. Prior to joining the Company, Ms. Kazeil held the Chief Financial Officer position at Sinopec Canada. Ms. Kazeil's experience includes serving as Vice President, Finance of Daylight Energy Ltd. from 2008 to 2011, and prior thereto Ms. Kazeil held increasingly senior finance roles with Sword Energy Ltd. and its predecessor Thunder Energy Trust from 2004 to 2008, including as Vice President, Finance and Chief Financial Officer. Ms. Kazeil started her accounting career at KPMG LLP in 2001. Ms. Kazeil is a Chartered Professional Accountant and holds a Bachelor of Commerce degree from the University of Ottawa and a Bachelor of Education degree from the University of Saskatchewan.

Michelle Radomski

Ms. Radomski is the Vice President, Land of PrairieSky and has more than 30 years of oil and natural gas industry experience specializing in land negotiation, contracts and administration. Prior to joining PrairieSky, Ms. Radomski was Vice-President, Land with Range GP since October 1, 2010, and prior thereto held leadership roles with Monterey Exploration Ltd., Baytex Energy Corp., Canadian Occidental Petroleum Ltd. (predecessor to Nexen Inc.) and Imperial Oil Ltd. Ms. Radomski is active in several industry groups and committees, including as President of the Canadian Association of Petroleum Landmen for 2014/2015 and co-chair of the 2014 CAPL Freehold PNG Lease Committee.

Corporate Cease Trade Orders or Bankruptcies

During the past ten years, none of the current directors and executive officers of PrairieSky is or has been a director, chief executive officer or chief financial officer of any company that: (i) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, while that person was acting in the capacity as director, chief executive officer or chief financial officer; (ii) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, 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. Other than disclosed below, none of the directors or executive officers of PrairieSky is as at the date of this AIF, or has been within ten years before the date of this AIF, a director or executive officer of any company 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.

Mr. Grant Zawalsky and Ms. Margaret McKenzie, each of whom are directors of the Company, were each directors of Endurance Energy Ltd. ("**Endurance**"), a corporation engaged in the exploration and production of natural gas. Endurance filed for creditor protection under the *Companies Creditors' Arrangement Act* on May 30, 2016. Ms. McKenzie resigned as a director of Endurance on March 31, 2016 and Mr. Zawalsky resigned as a director on November 1, 2016.

Personal Bankruptcies

None of the directors or executive officers of PrairieSky has nor any shareholder holding sufficient number of securities of the Company to affect materially the control of the Company, within the past ten years, 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 proposed director.

Penalties or Sanctions

No director, executive officer or promoter of PrairieSky nor any shareholder holding sufficient number of securities of the Company to affect materially the control of the Company, has been subject to any penalties or sanctions imposed by a court, securities regulatory authority or other regular authority or has entered into a settlement agreement with a securities regulatory authority.

AUDIT COMMITTEE

Audit Committee

The full text of the Audit Committee mandate is included in Appendix C of this AIF.

Composition of Audit Committee

PrairieSky's Audit Committee consists of Ms. McKenzie (Chair) and Messrs. Estey and Steeves. All members of the Audit Committee are independent and financially literate as those terms are used under National Instrument 52-110 - *Audit Committees*. See "*Directors and Executive Officers – Board of Directors of PrairieSky*".

Pre-Approval Policies and Procedures

The Audit Committee has adopted specific policies and procedures for the engagement of non-audit services. The policies and procedures allow for the pre-approval of certain services. For additional services, the audit committee pre-approves expenditures with a dollar limit for services. The Audit Committee must pre-approve any costs that exceed these limits. All audit and non-audit services are reported to the Audit Committee quarterly.

External Auditor Service Fees

	Year Ended December 31, 2016	**Year Ended December 31, 2017**
Audit fees(1)	$203,800	$294,350
Audit-related fees(2)	$-	$18,190
Tax fees(3)	$13,939	$15,623
Total	$217,739	$328,163

Notes:

(1) Audit fees consist of aggregate fees billed for the audit of PrairieSky's annual financial statements, reviews of interim consolidated financial statements for the quarters of 2016 and 2017 fiscal years, or services that are normally provided in connection with statutory and regulatory filings or engagements.

(2) Audit-related fees consist of aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of PrairieSky's financial statements and are not reported as Audit Fees.

(3) Aggregate fees billed related to tax services.

CONFLICTS OF INTEREST

Certain of the directors and executive officers of the Company are engaged in, and may continue to be engaged in, other activities in the industries in which the Company operates from time to time. The ABCA provides that in the event that an officer or director is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction, unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

As at the date hereof, there are no legal proceedings that PrairieSky is a party to, or that any of PrairieSky's property is the subject of, that is material to PrairieSky, and there are no such material legal proceedings known to be contemplated. For the purposes of the foregoing, a legal proceeding is not considered to be "material" to PrairieSky if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of PrairieSky's consolidated current assets, provided that if any proceeding presents in large degree the same legal and factual issues as other proceedings pending or known to be contemplated, we have included the amount involved in the other proceedings in computing the percentage.

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of any directors or executive officers of PrairieSky, any shareholder who beneficially owns more than 10% of the Common Shares or any known associate or affiliate of such persons in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Company.

TRANSFER AGENT AND REGISTRAR

TSX Trust Company at its principal offices in Calgary, Alberta acts as the transfer agent and registrar for the Common Shares.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Company did not enter into any material contracts within the most recently completed financial year, or before the most recently completed financial year but which are still in effect.

INTERESTS OF EXPERTS

Names of Experts

The only persons or companies who are named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by the Company during, or relating to, the Company's most recently completed financial year, and whose profession or business gives authority to the report, valuation statement or opinion made by the person or company, are KPMG LLP, our independent auditors and GLJ, our independent engineering evaluator.

Interest of Experts

KPMG LLP is the auditor of the Company and is independent with respect to the Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

As at the date hereof, the designated professionals (as defined in NI 51-102) GLJ, beneficially owned, directly or indirectly, less than 1% of our outstanding securities including the securities of our associate or affiliate entities.

In addition, none of the aforementioned persons or companies, nor any partner, 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 PrairieSky.

ADDITIONAL FINANCIAL AND OTHER INFORMATION

Additional information about the Company may be found on SEDAR at www.sedar.com. Additional financial information is provided in PrairieSky's audited financial statements for the period ended December 31, 2017, and the accompanying management's discussion and analysis. Information about remuneration and indebtedness of directors and officers of PrairieSky, principal holders of the Common Shares and securities authorized for issuance under security-based compensation of the Company, will be contained in the Information Circular and Proxy Statement of the Company which relates to the Annual General Meeting of Shareholders to be held on April 24, 2018.

For copies of the financial statements of the Company and accompanying management's discussion and analysis and the information circular and proxy statement and additional copies of the AIF (in certain circumstances reasonable fees may apply) please contact:

Corporate Secretary
PrairieSky Royalty Ltd.
Suite 1700, 350 – 7th Avenue S.W.
Calgary, Alberta T2P 3N9
Telephone: 587.293.4000
Fax: 587.293.4001

APPENDIX A

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

To the board of directors of PrairieSky Royalty Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs.

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

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 the Company evaluated for the year ended December 31, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	December 31, 2017	Canada	-	966,439	-	**966,439**

6. In our opinion, the reserves data 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 reports 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:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, January 23, 2018

"Originally Signed By"

Chad P. Lemke, P. Eng.
Vice President

APPENDIX B

Form 51-101F3

Report of Management and Directors on Oil and Gas Disclosure

Management of PrairieSky Royalty Ltd. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

Independent qualified reserves evaluator has evaluated the Company's reserves data. The reports of the independent qualified reserves evaluator is presented in Appendix A of this Annual Information Form.

The Reserves Committee of the Board of Directors of the Company has

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

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

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

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

(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 the Forms 51-101F2, which are the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

(signed) "*Andrew Phillips*"
Andrew Phillips
President & Chief Executive Officer

(signed) "*Cameron Proctor"*
Cameron Proctor
Chief Operating Officer

(signed) "*Sheldon Steeves*"
Sheldon Steeves
Director, Chair of the Reserves Committee

(signed) "*Margaret McKenzie*"
Margaret McKenzie
Director, Member of the Reserves Committee

DATED as of this 26th day of February, 2018.

APPENDIX C

AUDIT COMMITTEE MANDATE

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of PrairieSky Royalty Ltd. (the "**Company**"). Its primary duties and responsibilities are to: review management's identification of principal financial risks and monitor the process to manage such risks; oversee and monitor the integrity of the Company's accounting and financial reporting processes, financial statements and system of internal controls regarding accounting and financial reporting and accounting compliance; oversee audits of the Company's financial statements; oversee and monitor the qualifications, independence and performance of the Company's external auditors; provide an avenue of communication among the external auditors, management and the Board; and report to the Board regularly.

Composition of Committee

The Committee shall consist of not less than three directors as determined by the Board, all of whom shall qualify as independent directors within the meaning attributed to such term in National Instrument 52-110 - Audit Committees (as implemented by the Canadian Securities Administrators and as amended from time to time) ("**NI 52-110**").

All members of the Committee shall be financially literate, within the meaning attributed to such term in NI 52-110, and at least one member shall have accounting or related financial management expertise as the Board interprets such qualification in its business judgment.

Committee members may not, other than in their capacities as members of the Committee, the Board or any other committee of the Board, as applicable, accept directly or indirectly any consulting, advisory or other compensatory fee from the Company or any subsidiary of the Company, or be an "affiliated entity" (within the meaning attributed to such term in NI 52-110) of the Company or any subsidiary of the Company. For greater certainty, directors' fees and fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the Company that are not contingent on continued service should be the only compensation a Committee member receives from the Company.

Committee members will include only duly elected directors of the Company. At the request of the Committee, certain members of the Company's senior management and others may attend Committee meetings on an ad hoc or a regular basis, as required.

Appointment of Committee Members

Members of the Committee shall be appointed or continued as necessary at a meeting of the Board, provided that any member may be removed or replaced at any time by the Board and shall in any event cease to be a member of the Committee upon ceasing to be a member of the Board. Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

Chair

The Board shall appoint the Chair of the Committee (the "**Chair**"). If the Chair is unavailable or unable to attend a meeting of the Committee, the Chair shall ask another member to chair the meeting, failing which a member of the Committee present at the meeting shall be chosen by a majority of members of the Committee present at such meeting to preside over the meeting.

Committee Meetings

The Committee shall meet at least quarterly. The Chair may call additional meetings as required. In addition, a meeting may be called by the Board Chairman, the President & Chief Executive Officer, any member of the Committee or the external auditors.

Committee meetings may be held in person, by means of electronic, telephone or other communication facilities as to permit all persons participating in the meeting to hear each other or by combination of any of the foregoing.

At all meetings of the Committee every question will be decided by a majority of the votes cast on the question. In case of an equality of votes, the Chair presiding at any meeting shall not be entitled to a second or casting vote.

Notice of Meeting

Notice of the time and place of each Committee meeting may be given orally, or in writing, or by facsimile, or by electronic means to each member of the Committee at least 48 hours prior to the time fixed for such meeting. Notice of each meeting shall also be given to the external auditors of the Company.

A Committee member and the external auditors may, in any manner, waive notice of the Committee meeting. Attendance of a member at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

Quorum

A majority of Committee members, present in person, by electronic, telephone or other communication facilities or by a combination thereof, shall constitute a quorum. In addition, if an ex officio, non-voting member's presence is required to attain a quorum of the Committee, then the said member shall be allowed to cast a vote at the meeting.

Attendance at Meetings

The Committee shall have the right to determine who shall, and who shall not, be present at any time during a meeting of the Committee. The Committee may, by specific invitation, have other resource persons in attendance.

Directors, who are not members of the Committee, may attend Committee meetings, on an ad hoc basis, upon prior consultation and approval by the Chair or by a majority of the members of the Committee.

The Committee shall meet "in-camera" with the external auditors at least quarterly (in connection with the preparation of the annual and quarterly financial statements), and at such other times as the external auditors and the Committee consider appropriate

The Vice-President, Finance & Chief Financial Officer or any other person holding a similar role in accounting, risk, compliance and/or audit are expected to be available to attend the Committee's meetings or portions thereof, unless otherwise excused from all or part of any such meeting by the Committee Chair.

Minutes

The Committee shall appoint a secretary who need not be a member of the Committee. The secretary shall keep minutes of the meetings of the Committee. Minutes of Committee meetings shall be sent to all

Committee members and the external auditors. The full Board shall be kept informed of the Committee's activities by a report following each Committee meeting, unless each Board member who is not also a member of the Committee is in attendance at such Committee meeting.

Specific Responsibilities

Review Procedures

Review and update the Committee's mandate annually, or sooner, where the Committee deems it appropriate to do so. Provide a summary of the Committee's composition and responsibilities in the Company's annual information form or other public disclosure documentation.

Annual Financial Statements

1. Discuss and review with management and the external auditors, the Company's annual audited financial statements and related documents prior to their filing or distribution. Such review to include:

    (a) The annual audited financial statements, including accounting policies and significant management estimates and judgments and any major issues as to the adequacy of the Company's internal controls and disclosure controls and procedures;

    (b) Management's Discussion and Analysis;

    (c) A review of the external auditors' audit examination of the financial statements and their report thereon;

    (d) Review of any significant changes required in the external auditors' audit plan;

    (e) A review of any serious difficulties or disputes with management encountered during the course of the audit, including any restrictions on the scope of the external auditors' work or access to required information; and

    (f) A review of other matters related to the conduct of the audit, which are to be communicated to the Committee under generally accepted auditing standards.

2. Following completion of the matters contemplated above and review of consistency of disclosure, recommend approval to the Board of the Company's:

    (a) Year-end audited financial statements; and

    (b) Management's Discussion and Analysis.

Quarterly Financial Statements

3. Review with management and the external auditors and either approve (such approval to include the authorization for their filing or distribution) or formally recommend for approval to the Board, the Company's:

    (a) Quarterly unaudited financial statements and related documents, including Management's Discussion and Analysis; and

    (b) Any significant changes to the Company's accounting policies.

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Other Financial Filings and Public Documents

4. The Committee is to review prospectuses, annual information forms (AIF), business acquisition reports (BARs) and all other public disclosure containing audited or unaudited financial information before release and prior to Board approval.

5. Review and discuss with management financial information, including annual and interim earnings press releases, the use of "pro forma" or non-GAAP financial information and guidance, contained in any filings with the securities regulators or news releases related thereto (or provided to analysts or rating agencies). Consideration should be given as to whether the information is consistent with the information contained in the financial statements of the Company. Such review and discussion should occur before public disclosure and may be done generally (consisting of discussing the types of information to be disclosed and the types of presentations to be made). The Committee must be satisfied that adequate procedures are in place for the review of PrairieSky's disclosure of all other financial information and shall periodically assess the accuracy of those procedures.

Internal Control Environment

6. Ensure that management provides to the Committee an annual report on the Company's control environment as it pertains to the Company's financial reporting process and controls.

7. Review with the President & Chief Executive Officer, the Vice-President, Finance & Chief Financial Officer and the external auditors: (i) all significant deficiencies and material weaknesses in the design or operation of the Company's internal controls and procedures for financial reporting which could adversely affect the Company's ability to record, process, summarize and report financial information required to be disclosed by the Company in the reports that it files or submits under applicable Canadian federal and provincial legislation and regulations within the required time periods, and (ii) any fraud, whether or not material, that involves management of the Company or other employees who have a significant role in the Company's internal controls and procedures for financial reporting.

8. Review and discuss significant financial risks or exposures and assess the steps management has taken to monitor, control, report and mitigate such risk to the Company.

9. Review management's processes in place to prevent and detect fraud.

10. Review significant findings prepared by the external auditors together with management's responses, if any.

11. Review the audit plans of the external auditors and enquire as to the extent the planned scope can be relied upon to detect weaknesses in internal controls, fraud or other illegal acts. Any significant recommendations made by the auditors for the strengthening of internal controls shall be reviewed and discussed with management.

Other Review Items

12. Review policies and procedures with respect to officers' and directors' expense accounts and perquisites, including their use of corporate assets.

13. Review all related party transactions between the Company and any officers or directors, including affiliations of any officers or directors as the Committee considers appropriate.

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14. Review legal and regulatory matters, including correspondence and filings with regulators and governmental agencies, which may have a material impact on the interim or annual financial statements, related corporate compliance policies, and programs and reports received from regulators or governmental agencies, including but not limited to reporting documents filed under the *Extractive Sector Transparency Measures Act*.

15. Review policies and practices with respect to risk management, including trading and hedging activities and insurance.

16. Review policies and practices with respect to cybersecurity risk management, including but not limited to: (a) assessing best practices from industry associations and recognized information security organizations in relation to the Company's business and operations; and (b) reviewing third party vulnerability and security tests and assessments performed by or on behalf of the Company.

17. In conjunction with the Corporate Governance Committee, review procedures for the receipt, retention and treatment of complaints received by the Company, regarding accounting, internal accounting controls, or auditing matters including confidential, anonymous submissions by employees of the Company, regarding accounting, internal accounting controls, or auditing matters.

18. Meet on a periodic basis separately with management.

External Auditors

19. Be directly responsible, in the Committee's capacity as a committee of the Board and subject to the rights of shareholders and applicable law, for the appointment, compensation, retention and oversight of the work of the external auditors (including resolution of disagreements between management and the external auditors regarding financial reporting) for the purpose of preparing or issuing an audit report, or performing other audit, review or attest services for the Company. The external auditors shall report directly to the Committee.

20. Meet on a regular basis with the external auditors (without management present) and have the external auditors be available to attend Committee meetings or portions thereof at the request of the Chair or by a majority of the members of the Committee.

21. Obtain and review a report from the external auditors at least annually regarding:

    (a) The external auditors' internal quality-control procedures;

    (b) Any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with those issues; and

    (c) Review and discuss with the external auditors all relationships that the external auditors and their affiliates have with the Company and its affiliates in order to determine the external auditors' independence.

22. Review and evaluate:

    (a) The external auditors' performance and the lead partner of the external auditors' team's performance, and make a recommendation to the Board regarding the reappointment of the external auditors at the annual meeting of the Company's shareholders or regarding

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the discharge of such external auditors and the subsequent nomination of a new external auditor;

(b) The terms of engagement of the external auditors together with their proposed fees;

(c) External audit plans and results; and

(d) Any other related audit engagement matters.

23. Ensure the rotation of partners on the audit engagement team in accordance with applicable law. Consider whether, in order to assure continuing external auditor independence, it is appropriate to adopt a policy of rotating the external auditing firm on a regular basis.

24. Consider and review with the external auditors and management:

(a) Significant findings during the year and management's responses and follow-up thereto;

(b) Any difficulties encountered in the course of their audits, including any restrictions on the scope of their work or access to required information, and management's response;

(c) Any significant disagreements between the external auditors and management; and

(d) Any changes required in the planned scope of their audit plan.

Approval of Audit and Non-Audit Services

25. Review and, where appropriate, approve the provision of all permitted non-audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors (subject to de minimis exceptions for non-audit services described in NI 52-110, the rules and forms under applicable Canadian federal and provincial legislation and regulations, which services are approved by the Committee prior to the completion of the audit).

26. Review and, where appropriate and permitted, approve the provision of all audit services (including the fees and terms thereof) in advance of the provision of those services by the external auditors.

27. If the pre-approvals contemplated in paragraphs 25 and 26 are not obtained, approve, where appropriate and permitted, the provision of all audit and non-audit services promptly after the Committee or a member of the Committee to whom authority is delegated becomes aware of the provision of those services.

28. Delegate, if the Committee deems necessary or desirable, to subcommittees consisting of one or more members of the Committee, the authority to grant the pre-approvals and approvals described in paragraphs 25 through 27. The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

29. The Committee may establish policies and procedures for the pre-approvals described in paragraphs 25 and 26, so long as such policies and procedures are detailed as to the particular service, the Committee is informed of each service and such policies and procedures do not include delegation of the Committee's responsibilities under applicable Canadian federal and provincial legislation and regulations to management.

Other Matters

30. Review and concur in the appointment, replacement, reassignment, or dismissal of the Vice-President, Finance & Chief Financial Officer.

31. Report Committee actions to the Board with such recommendations, as the Committee may deem appropriate.

32. Conduct or authorize any review or investigation into any matters within the Committee's scope of responsibilities. The Committee shall have unrestricted access to personnel and information and any resources necessary to carry out its responsibility. The Committee shall be empowered to retain, obtain advice or otherwise receive assistance from independent counsel, accountants, or others to assist it in the conduct of any investigation as it deems necessary and in carrying out of its duties. The Committee shall have the authority to set and pay compensation for any such advisors.

33. The Committee shall review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Board for approval.

34. Perform such other functions as required by law, the Company's articles or bylaws, or the Board.

35. Consider any other matters referred to it by the Board.

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