PRAIRIESKY ROYALTY LTD

2014 ANNUAL INFORMATION FORM

February 23, 2015

TABLE OF CONTENTS

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 our future performance, are provided to allow readers to better understand our 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. We believe 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 statements speak only as of the date of this AIF. We assume no obligation to revise or update these statements except as required pursuant to applicable securities laws.

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

- PrairieSky Royalty Ltd.'s (*PrairieSky* or the *Company*) 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 petroleum 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 expectation that the Company will be successful in strategically seeking additional petroleum and natural gas royalty assets that provide the Company with medium-term to long-term value enhancement potential;
- 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 petroleum 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 the petroleum and natural gas development on the Royalty Properties;
- the performance and characteristics of the Royalty Properties, including additional upside potential in 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 petroleum 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), operators and working interest owners on the Royalty Properties as well as to provide necessary services to the Company;
- liabilities inherent in petroleum 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 and working interest owners on the Royalty Properties;
- competition for, among other things, third party capital and acquisitions of reserves, additional petroleum 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 associated with petroleum 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;
- a decrease or elimination of the payment of dividends by the Company as a result of a Board 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 we believe that the assumptions underlying such forward-looking statements are reasonable, we 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 working interest owners on the GORR Lands (as defined herein) 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 GORR Lands 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 working interest owners on the GORR Lands to operate in a safe, efficient and effective manner;
- the timely receipt of any required regulatory approvals by lessees on the Fee Lands or working interest owners on the GORR Lands;

- the willingness and financial capability of the lessees on the Fee Lands and working interest owners on the GORR Lands 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 acquisitions and third party development;
- 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 petroleum 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 petroleum 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 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. 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 the GORR Lands in this AIF has been presented on a gross acre basis. For the Fee Lands, gross acres refers 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 refers 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 or GORR percentage royalty ownership interest held in the 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 petroleum 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;

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 farmout, sell or otherwise exchange for consideration of a GORR Interest.

Encana Royalty Acquisition means the acquisition by the Company from Encana of: (i) fee simple mineral title in lands prospective for petroleum, natural gas, natural gas liquids 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) an irrevocable, perpetual licence to certain proprietary seismic data of Encana; and (v) certain other related assets as set forth in the Purchase and Sale Agreement between the Company and Encana;

Fee Lands means lands prospective for petroleum, natural gas and certain other mines and minerals in which the Company holds an undivided 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 petroleum and natural gas production from non-government owned lands within Alberta;

GAAP means generally accepted accounting principles in Canada, which for Canadian reporting issuers is IFRS, as in effect from time to time;

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

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, 2014 and a preparation date of February 10, 2015**;**

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;

Governance Agreement means the governance agreement entered into between Encana and the Company upon closing of the IPO;

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

IFRS means International Financial Reporting Standards as issued by the International Accounting Standards Board, as adopted by the Canadian Accounting Standards Board;

Investor Liquidity Agreement means the investor liquidity agreement entered into between Encana and the Company upon closing of the IPO;

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;

Lease Issuance and Administration Agreements means the lease issuance and administration agreements entered into between Encana and the Company as part of the Encana Royalty Acquisition;

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

net means: (i) in relation to the Company's interest in production or reserves, its working interest (operating or non-operating) share, if any, after deduction of royalty obligations, plus the Company's Lessor Interests, GRT Interests and GORR Interests in production or reserves; (ii) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest or 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 an 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*;

NI 52-110 means National Instrument 52-110 — *Audit Committees*;

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 oil and NGL;

Purchase and Sale Agreement means the agreement of purchase and sale, dated May 27, 2014, entered into between Encana and the Company, pursuant to which the Company completed the Encana Royalty Acquisition;

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;

Resource-style plays means an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section;

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

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 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;

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;

Transition Services Agreement means the transition services agreement between Encana and the Company entered into upon completion of the IPO;

Trust Agreement means the trust agreement between Encana and the Company entered into upon completion of the Encana Royalty Acquisition; 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
Mcfe	thousand cubic feet equivalent
MMbtu	million British thermal units
MMcf	million cubic feet
MMcf/d	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 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 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 dissolved into 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 GP and Range Royalty.

As of December 31, 2014 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 BUSINESS

The following is a summary description of the development of PrairieSky's business since commencing active business on May 27, 2014.

Year Ended December 31, 2014

The Encana Royalty Acquisition

On May 27, 2014, the Company completed the Encana Royalty Acquisition, pursuant to which it acquired a royalty business from Encana with assets comprised of: (i) fee simple mineral title in lands prospective for petroleum, natural gas, natural gas liquids 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 Licence; and (v) certain other related assets as set forth in the Purchase and Sale Agreement. In consideration for the acquisition by the Company of the Fee Lands, Lessor Interests, GORR Interests, seismic data and other related assets pursuant to the Purchase and Sale Agreement, PrairieSky issued 129,994,000 Common Shares to Encana. Following the completion of the Encana Royalty Acquisition, Encana held 130,000,000 Common Shares.

In connection with the Encana Royalty Acquisition, the Company entered into the Lease Issuance and Administration Agreements, the Seismic License Agreement and the Trust Agreement. See "*Material Contracts*".

The Initial Public Offering

On May 29, 2014, PrairieSky completed the IPO whereby Encana sold 52,000,000 Common Shares to the public and the Common Shares were listed and posted for trading on the TSX. On June 3, 2014, the Company announced that in connection with the IPO the over-allotment option granted to the underwriters to purchase (for resale) up to an additional 7,800,000 Common Shares from Encana at the offering price had been exercised. Following completion of the IPO and exercise of the over-allotment option, Encana owned 70,200,000 Common Shares, representing 54% of the issued and outstanding Common Shares. The Company did not receive any proceeds from the IPO.

In connection with the IPO, the Company entered into the Governance Agreement, the Investor Liquidity Agreement and the Transition Services Agreement with Encana.

The September Secondary Offering

On September 26, 2014, PrairieSky and Encana announced the completion of a secondary offering of 70,200,000 Common Shares at a price of $36.50 per share, for aggregate gross proceeds to Encana of approximately $2.6 billion. The Company did not receive any of the proceeds from the September Secondary Offering. Following the closing of the September Secondary Offering, Encana no longer held any interest in PrairieSky and as a result the Governance Agreement and the Investor Liquidity Agreement terminated in accordance with their respective terms.

Range Royalty Acquisition

On December 19, 2014, PrairieSky announced the completion of the acquisition of Range Royalty and Range GP in exchange for the issuance of approximately 19.3 million Common Shares to former Range Royalty unitholders by way of a plan of arrangement under the ABCA. Pursuant to Range Royalty Acquisition, Range Royalty unitholders received 0.8 of a Common Share for each Range Royalty unit held. Based on the closing price of the Common Shares on December 19, 2014, the effective date of the Range Royalty Acquisition, the total consideration paid by the Company for the Range Royalty Acquisition was approximately $625.3 million.

Completion of the Range Royalty Acquisition increased PrairieSky's acreage position to 10.2 million acres, including approximately 6.4 million acres of Fee Lands, 3.4 million acres of GORR Lands, 0.2 million acres of GRT Lands and 0.2 million acres of Crown Interest Lands. The Range Royalty Acquisition provided PrairieSky with a significant land position in the Viking light oil fairway of western Saskatchewan, and expanded PrairieSky's acreage position in active drilling areas of the Alberta Deep Basin, including 70,000 acres of GORR Lands in the Duvernay contiguous with PrairieSky's existing Fee Land position and exposure to Wilrich drilling at Edson.

Significant Acquisitions

Other than the Encana Royalty Acquisition and the Range Royalty Acquisition, during the period ended December 31, 2014, the Company did not complete any acquisitions that would be considered significant pursuant to NI 51-102.

PrairieSky has filed business acquisition reports in Form 51-102F4 in connection with each of the Encana Royalty Acquisition and the Range Royalty Acquisition, which are available on SEDAR at www.sedar.com.

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 GORR Interests in Canada. The Company is focused on encouraging third parties to actively develop the Royalty Properties while strategically seeking additional petroleum and natural gas 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 complimenting 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 and natural gas are produced from such properties. The Company's costs are primarily Freehold Mineral Taxes, corporate income taxes and administrative expenses. Costs typically related to upstream drilling, equipment, production and asset retirement obligations are not incurred by the Company; instead, these costs are incurred by the 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; and (iii) 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 primarily from royalties payable by lessees and working interest owners from petroleum and natural gas production on the Royalty Properties and revenues derived from related activities, including lease issuance bonuses 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 contractual royalties, net profit, production or such other similar forms of royalty encumbrances; (iii) the GRT Lands; and (iv) related activities, including lease issuance bonuses 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 as a royalty a percentage of production on its properties delivered in-kind. The Company does not currently take in-kind a meaningful amount of its petroleum and natural gas royalty volumes.

Lessor Interests

The Company's royalty revenue is substantially derived from the Lessor Interests in respect of producing wells located on the Fee Lands. The Company holds Fee Interests in approximately 6.4 million acres of Fee Lands. From commencement of operations on May 27, 2014 to December 31, 2014, the Lessor Interests provided approximately 97% of the total royalty revenue of the Company, of which royalty revenue derived from production of petroleum and natural gas accounted for approximately 74% and 26%, respectively. As part of the Encana Royalty Acquisition, the Company and Encana entered into the Lease Issuance and Administration Agreements, pursuant to which the Company agreed to issue leases to Encana on certain of the Fee Lands.

For the period ended December 31, 2014, average net production associated with the Lessor Interests was approximately 15,560 boe/d, with approximately 47.3 MMcf/d of natural gas production, approximately 6,249 bbls/d of oil production and approximately 1,430 bbls/d of NGL production, generating total royalty revenue of approximately $174.0 million. In addition, in 2014, the lease rental income associated with the Lessor Interests was approximately $7.2 million.

GORR Interests

The GORR Lands are governed by contractual arrangements whereby the GORR Interests have been reserved to the Company, typically on lands where the Company does not have fee simple mineral title ownership. The GORR Interests, with few exceptions, expire upon the termination of the underlying leases. Termination of an underlying lease on Crown land occurs only after any drilling or production activity has ceased and the operator of the lease has received a reclamation certificate.

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 from well production 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 fashion, 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 3.4 million acres of GORR Lands. From commencement of operations on May 27, 2014 to December 31, 2014, average net production associated with the GORR Lands was approximately 689 boe/d, with approximately 2.7 MMcf/d of natural gas production, approximately 180 bbls/d of oil production and approximately 56 bbls/d of NGL production, generating total royalty revenue of approximately $6.1 million. In 2014, the GORR Interests provided approximately 3% of the total royalty revenue of PrairieSky.

GRT Interests

Through the Range Royalty Acquisition, the Company acquired approximately 0.2 million acres of GRT Lands, complimenting a minor holding of GRT Interests previously held by the Company. 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.

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 incorporation or proposed for the current financial year.

Personnel

As of December 31, 2014, the Company had 65 full time employees and 5 part time employees.

Cyclical and Seasonal Nature of Industry

PrairieSky's operational results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on PrairieSky financial condition. See "*Risk Factors*".

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for 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 minimal or 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. 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 lessees and/or 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 geological plays to maximize the value on the Fee Lands. 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 by GLJ as set forth in the GLJ Report. The effective date of the information provided in the GLJ Report is December 31, 2014 and the report has a preparation date of February 10, 2015. The GLJ Report evaluated, as at December 31, 2014, 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 report 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, but after providing for estimated royalties, production costs, capital, production taxes, development costs, other income and future capital expenditures. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the reserves estimated by GLJ represent the fair market value of the reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. 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 evaluations 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. All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of properties. There can be no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural gas and NGL reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered.

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 and British Columbia**.** Also, 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, 2014
Forecast Prices and Costs

Summary of Reserves

Reserves Category	Natural Gas				Light and Medium Crude Oil		Heavy Crude Oil		NGL	
	Coalbed Methane		Other[4]							
	Gross[1][3]	Net[2][3]	Gross[1][3]	Net[2][3]	Gross[1][3]	Net[2][3]	Gross[1][3]	Net[2][3]	Gross[1][3]	Net[2][3]
	(Bcf)		(Bcf)		(Mbbl)		(Mbbl)		(Mbbl)	
Proved										
Developed Producing	-	34.4	-	59.4	-	11,215	-	283	-	2,664
Developed Non-Producing	-	-	-	-	-	5	-	-	-	16
Undeveloped	-	-	-	-	-	-	-	-	-	-
Total Proved	-	34.4	-	59.4	-	11,220	-	283	-	2,680
Total Probable	-	6.3	-	12.4	-	2,506	-	44	-	554
Total Proved Plus Probable	-	40.7	-	71.9	-	13,726	-	328	-	3,234

** Numbers may not add due to rounding.*

Notes:

(1) Gross reserves represent the working interest share before deduction of any royalty obligations and without including any royalty interests.

(2) Net reserves represent the working interest share after deduction of royalty obligations, plus royalty interests in production or reserves.

(3) 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.

(4) Other includes natural gas other than coalbed methane.

Summary of Net Present Values of Future Net Revenue

Reserves Category	Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year)				
	0%	5%	10%	15%	20%
			(M$)		
Proved					
Developed Producing	1,603,629	1,082,400	814,943	655,908	551,324
Developed Non-Producing	1,198	986	848	751	678
Undeveloped	0	0	0	0	0
Total Proved	1,604,827	1,083,386	815,791	656,659	552,003
Total Probable	458,748	197,987	108,693	69,730	49,456
Total Proved Plus Probable	2,063,575	1,281,374	924,484	726,389	601,458

** Numbers may not add due to rounding.*

Reserves Category	Net Present Value of Future Net Revenue After Income Taxes Discounted at (%/year)				
	0%	5%	10%	15%	20%
			(M$)		
Proved					
Developed Producing	1,327,815	900,896	681,687	551,051	464,940
Developed Non-Producing	902	738	632	558	504
Undeveloped	—	—	—	—	—
Total Proved	1,328,717	901,633	682,319	551,610	465,444
Total Probable	345,040	148,639	81,483	52,224	37,019
Total Proved Plus Probable	1,673,757	1,050,272	763,801	603,834	502,463

** Numbers may not add due to rounding.*

Additional Information Concerning Future Net Revenue (Undiscounted) as of December 31, 2014

Reserves Category	Royalty Revenue	Royalty and Production Mineral Taxes	Operating Costs	Development Costs(1)	Abandonment and Reclamation Costs(1)	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Income Taxes
					($ millions)			
Proved								
Developed Producing	1,603,629	—	—	—	—	1,603,629	275,814	1,327,815
Developed Non-Producing	1,198	—	—	—	—	1,198	296	902
Undeveloped	0	—	—	—	—	—	—	—
Total Proved	1,604,827	—	—	—	—	1,604,827	276,109	1,328,717
Total Probable	458,748	—	—	—	—	458,748	113,708	345,040
Total Proved Plus Probable	2,063,575	—	—	—	—	2,063,575	389,818	1,673,757

** Numbers may not add due to rounding.*

Note:
(1) No development costs or abandonment and reclamation costs are associated with the estimated future net revenue from the reserves attributed to the Royalty Properties as the Company does not hold any working interests in the Royalty Properties and is not responsible for such costs.

Future Net Revenue by Production Group as of December 31, 2014

		Future Net Revenue Before Income Taxes)[3] (Discounted at 10% per year)		
		M$	**$/boe**	**$/Mcfe**
Proved Producing				
	Light & Medium Oil[1]	523,924	41.29	6.88
	Heavy Oil[1]	13,860	46.76	7.79
	Natural Gas[2]	201,698	18.47	3.08
	Coal Bed Methane	75,460	12.81	2.13
		814,943	**27.35**	**4.56**
Total Proved				
	Light & Medium Oil[1]	524,576	41.30	6.88
	Heavy Oil[1]	13,870	46.76	7.79
	Natural Gas[2]	201,835	18.47	3.08
	Coal Bed Methane	75,511	12.81	2.13
		815,791	**27.36**	**4.56**
Total Proved Plus Probable				
	Light & Medium Oil[1]	597,891	38.45	6.41
	Heavy Oil[1]	15,128	44.32	7.39
	Natural Gas[2]	228,876	17.37	2.90
	Coal Bed Methane	82,589	11.83	1.97
		924,484	**25.64**	**4.27**

Notes:
(1) Including solution gas and other by-products
(2) Including by-products but excluding solution gas
(3) 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, discounted at 10%, 66% of the revenue is from combined crude oil and 34% is from natural gas. For the total proved plus probable reserves, 66% of the revenue is from combined crude oil and 34% is from 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, natural gas and NGL reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible 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) specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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, possible) 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;

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

(c) at least a 10% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible 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 pricing, inflation rate and exchange rate assumptions based on the GLJ (2015-01) Price Forecast in estimating reserves data using forecast prices and costs.

	Crude Oil	**Natural Gas**	**NGL**				
Year	**Edmonton Light[1]**	**Alberta AECO Spot Prices**	**Propanes**	**Butanes**	**Pentane Plus**	**Inflation Rate[2]**	**Exchange Rate[3]**
	($/bbl)	*($/MMbtu)*	*($/bbl)*	*($/bbl)*	*($/bbl)*	*(%/year)*	*($US/$Cdn)*
2015	*64.71*	*3.31*	*19.63*	*52.91*	*69.24*	*2.0*	*0.850*
2016	*80.00*	*3.77*	*32.00*	*60.80*	*85.60*	*2.0*	*0.875*
2017	*85.71*	*4.02*	*38.57*	*65.14*	*91.71*	*2.0*	*0.875*
2018	*91.43*	*4.27*	*41.14*	*69.49*	*97.83*	*2.0*	*0.875*
2019	*97.14*	*4.53*	*43.71*	*73.83*	*103.94*	*2.0*	*0.875*
2020-2024	*102.86-112.67*	*4.78-5.71*	*46.29-50.70*	*78.17-85.63*	*110.06-120.56*	*2.0*	*0.875*
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year		

Notes:
(1) Edmonton Light Sweet 40° API/0.3% sulphur.
(2) Default cost inflation rate.
(3) The exchange rates used to generate Canadian benchmark reference prices in this table.

During 2014, the historical weighted average prices realized in respect of the production associated with the Royalty Properties were $4.26/Mcf for natural gas, $81.90/bbl for light and medium crude oil and $55.71/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, 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 Oil			**Heavy Oil**		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2013[1]	5,948	1,525	7,473			
Extensions	812	247	1,059			
Improved recovery						
Technical revisions	5,723	405	6,129	332	44	376
Discoveries						
Acquisitions	1,105	329	1,435	2		2
Dispositions						
Economic factors						
Production	(2,369)		(2,369)	(51)		(51)
December 31, 2014[2]	**11,220**	**2,506**	**13,726**	**283**	**44**	**328**

	Natural Gas			**Coal Bed Methane**		
	Proved (Bcf)	Probable (Bcf)	Proved Plus Probable (Bcf)	Proved (Bcf)	Probable (Bcf)	Proved Plus Probable (Bcf)
December 31, 2013[1]	42.1	9.2	51.3	45.0	8.5	53.5
Extensions	4.2	0.9	5.1	0.6	0.1	0.8
Improved recovery						
Technical revisions	12.6	(1.8)	10.8	(7.4)	(2.6)	(10.0)
Discoveries						
Acquisitions	13.0	4.1	17.1	0.9	0.3	1.2
Dispositions						
Economic factors						
Production	(12.5)		(12.5)	(4.7)		(4.7)
December 31, 2014[2]	**59.4**	**12.4**	**71.9**	**34.4**	**6.3**	**40.7**

	Natural Gas Liquids			**Oil Equivalent**		
	Proved (Mbbl)	Proved (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2013[1]	2,422	574	2,996	22,887	5,049	27,936
Extensions	291	63	354	1,899	489	2,388
Improved recovery						
Technical revisions	225	(173)	52	7,151	(462)	6,689
Discoveries						
Acquisitions	297	91	388	3,726	1,157	4,883
Dispositions						
Economic factors						
Production	(556)		(556)	(5,845)		(5,845)
December 31, 2014[2]	**2,680**	**554**	**3,234**	**29,818**	**6,234**	**36,052**

Note:
(1) December 31, 2013 opening balance from the reserve report prepared in connection with the Company's initial public offering in May 2014. See the Company's final long form prospectus dated May 22, 2014 for further information.
(2) Columns may not add due to rounding.

Significant Factors or Uncertainties

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, 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 restrictions.

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

As funding for development costs are the responsibility of the working interest owners on the applicable properties, and the Company does not hold any working interests in the Royalty Properties, the Company is not responsible for any development costs on the Royalty Properties and cannot advise as to the sources and costs of funding future development or the impact thereof on disclosed reserves or future net revenue.

Abandonment and Reclamation Costs

The Company has no abandonment and reclamation obligations as these are the responsibility of working interest owners.

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, predominantly all of which are located in Alberta and Saskatchewan and all of which are onshore. As the Company does not hold any working interests in the Royalty Properties, the net number of wells located on the Royalty Properties is nil.

	Natural Gas		Oil	
Area	**Producing**	**Non-Producing(1)**	**Producing**	**Non-Producing(1)**
Alberta	17,098	—	3,800	—
British Columbia	101	—	5	—
Saskatchewan	1,683	—	1,001	—

Note:

(1) As royalty revenues payable by third parties is 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 petroleum and natural gas land holdings of the Company with no attributed reserves as at December 31, 2014 and the acreage which is subject to a lease term expiry within one year.

	Fee Lands(1)(3)	GRT Lands(1)(3)	GORR Lands(2)(4)		Crown Interest Lands(2)(4)		
(thousands of acres)	**Gross Acres**	**Gross Acres**	**Gross Acres**	**Gross Acres expiring within one year**	**Gross Acres**	**Net Acres**	**Net Acres expiring within one year**
Alberta	2,036	17	897	114	200	200	1
Saskatchewan	110	3	510	27	6	6	5
BC	—	—	45	—	—	—	—
Intraprovincial	—	86	35		—	—	
Total	**2,146**	**106**	**1,487**	**141**	**206**	**206**	**6**

Notes:

(1) Title 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 the Fee Lands and GRT Lands are held in perpetuity. As such, there are no gross acres for which the Company's interests will expire during 2015.
(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 will be approximately 25%. 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.

Costs Incurred

Expenditure	Year Ended December 31, 2014
Property acquisition costs:	
Proved properties	376,174,919
Unproved properties	100,946,205
Total(1)	**477,121,124**

Note:

(1) Of Total Property acquisition costs $459,391,476 relates to the Range Royalty Acquisition, of which $364,629,919 is attributable to Proved properties and $94,761,557 is attributable to Unproved properties.

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, 2015 in the estimates of gross and net proved and gross probable reserves disclosed above under the heading "Reserves and Other Oil and Gas Information — Disclosure of Reserves Data". No field accounts for more than 20% of the production estimate.

Reserves Category	Natural Gas				Light and Medium Crude Oil		Heavy Crude Oil		NGL	
	Coalbed Methane		Other(4)							
	Gross(1)(3)	Net(2)(3)	Gross(1)(3)	Net(2)(3)	Gross(1)(3)	Net(2)(3)	Gross(1)(3)	Net(2)(3)	Gross(1)(3)	Net(2)(3)
	(Bcf)		*(Bcf)*		*(Mbbl)*		*(Mbbl)*		*(Mbbl)*	
Proved	-	3.5	-	8.5	-	1,539	-	34	-	385
Probable	-	-	-	0.1	-	36	-	-	-	6
Total Proved Plus Probable	-	3.5	-	8.6	-	1,575	-	34	-	391

** Numbers may not add due to rounding.*

Notes:

(1) Gross production represents the working interest share before deduction of any royalty obligations and without including any royalty interests.
(2) Net production represents the working interest share after deduction of royalty obligations, plus royalty interests.
(3) The Company differs from typical oil and natural gas producers in that all of its interests in reserves will be 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.
(4) Other includes natural gas other than coalbed methane.

Production History

The following table summarizes production, product prices received, royalties paid (Freehold Mineral Tax expense), operating expenses and resulting netback for the periods indicated below:

	Annual 2014	2014 Q4	Q3	Q2	Q1
Average daily production[1]					
Natural Gas *(MMcf/d)*	50.02	58.62	44.14	42.90	—
Light and Medium Crude Oil (*Mbbl/d*)	6.43	6.07	6.60	6.93	—
NGL *(Mbbl/d)*	1.49	1.44	1.49	1.58	—
Total *(Mboe/d)*	16.25	17.28	15.45	15.66	—
Average price realized[2]					
Natural Gas *($/Mcf)*	4.26	3.68	4.94	4.51	—
Light and Medium Crude Oil (*$/bbl*)	81.90	67.41	88.58	98.50	—
NGL *($/bbl)*	55.71	36.70	70.94	63.55	—
Total *($/boe)*	50.62	39.24	58.80	62.35	—
Freehold Mineral Tax expense					
Natural Gas *($/Mcf)*	(0.01)	(0.17)	0.17	0.09	—
Light and Medium Crude Oil (*$/bbl*)	4.08	3.93	4.19	4.14	—
NGL *($/bbl)*	—	—	—	—	—
Total *($/boe)*	1.59	0.80	2.28	2.07	—
Operating expense[3]					
Natural Gas *($/Mcf)*	$0.43	$0.48	$0.39	$0.39	—
Light and Medium Crude Oil (*$/bbl*)	$7.97	$8.86	$6.91	$8.56	—
NGL *($/bbl)*	—	—	—	—	—
Total *($/boe)*	4.49	4.75	4.05	4.86	—
Netback received[4]					
Natural Gas *($/Mcf)*	3.84	3.37	4.38	4.03	—
Light and Medium Crude Oil (*$/bbl*)	69.85	54.62	77.48	85.81	—
NGL *($/bbl)*	55.71	36.70	70.94	63.55	—
Total *($/boe)*	44.54	33.68	52.47	55.42	—

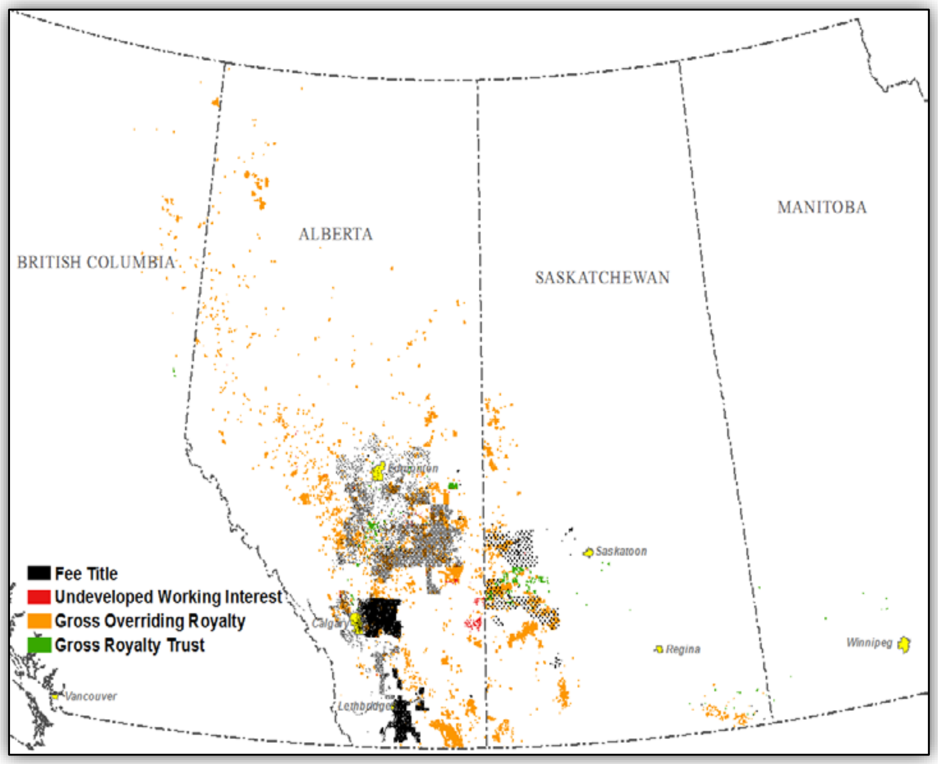
Notes:
(1) Represents net production.
(2) Excludes coal, sulfur and other revenue.
(3) Operating expenses include expenses associated with land administration, accounting and auditing functions necessary to administer and collect royalty payments and are allocated to natural gas and oil based on each product's share of that total product revenue.
(4) Netbacks are calculated by subtracting royalties paid (Freehold Mineral Tax expense) and operating expense from revenues.

Description of Properties

The assets of PrairieSky are comprised of: (i) the Fee Lands, encompassing approximately 6.4 million acres; (ii) the Lessor Interests; (iii) the GORR Interests, encompassing approximately 3.4 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 encompassing approximately 40,013 kilometers of 2D seismic and approximately 10,764 square kilometers of 3D seismic; and (vii) certain other related assets as set forth in the Purchase and Sale Agreement.

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

Approximately 17,000 leases are currently active on the Fee Lands and over 285 lessees are actively engaged in exploring for and producing petroleum and natural gas on the Fee Lands.



Fee Lands

The Company has one of the largest independently-owned portfolios of fee simple mineral title in Canada with approximately 6.4 million acres of Fee Lands, of which approximately 5.32 million acres are comprised of petroleum and/or natural gas rights, with or without the inclusion of coal rights and 1.1 million acres include only coal rights. For the period ended December 31, 2014, royalty revenue from the Fee Lands accounted for approximately 97% of the total royalty revenue of PrairieSky.

The Fee Lands include a geologically diverse portfolio of properties that span the entire 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 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 Falhar/Wilrich/Notikewin; (iv) the Jurassic to Base Mississippian, which includes the Rock Creek, Nordegg, Rundle Group, Banff and Alberta Bakken Formations; and (v) the Devonian, which includes the Nisku and the Duvernay Formations.

GORR Lands

The Company holds GORR Interests in approximately 3.4 million acres of GORR Lands. The substantial majority of the GORR Lands were acquired as part of the Range Royalty Acquisition. Most recent drilling activities on the GORR Lands were predominantly focused on the Viking Formation in southwestern Saskatchewan, the Wilrich and Duvernay Formations at Edson and the Duvernay Formation at Willesden Green.

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 through Alberta, Saskatchewan and British Columbia.

Crown Interest Lands

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

Certain Other Mines and Mineral Rights

Coal rights, precious stone and other mines and mineral rights, in addition to petroleum and natural gas, are included in substantially all the Fee Lands. The Fee Lands include a royalty interest in the 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 and current estimates of mining and transportation costs in Alberta, the Company does not currently consider coal, precious stone or these other mineral rights material to its business.

BORROWINGS

PrairieSky has an unsecured $75 million extendible revolving credit facility and an unsecured $25 million extendible operating credit facility (collectively, the Credit Facilities). Borrowings under the Credit Facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees. As at December 31, 2014, the Company had $100 million of available capacity under the Credit Facilities and $nil debt.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of petroleum and natural gas through agreements among the governments of Canada and Alberta, all of which should be carefully considered by investors in the oil and natural gas industry. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry in western Canada.

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 petroleum 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.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand primarily determines oil prices however, prices are also influenced by regional markets and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the availability of transportation, the value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the *NEB*). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB is currently undergoing a consultation process to update the current regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal Jobs, Growth and Long-term Prosperity Act, which received Royal Assent on June 29, 2012 (the *Prosperity Act*). In this transitory period, the NEB has issued, and is currently following, an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the National Energy Board Act".

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can be set by such supply and demand. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 cubic metres per day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement (*NAFTA*) among the governments of Canada, the United States and Mexico became effective on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36-month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

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

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

The Company will have the flexibility to negotiate and adapt its royalty arrangements with third parties to the appropriate circumstances, including in light of the existing royalty regime established by the Province of Alberta (as described below) and any amendments to that regime.

Crown (Province of Alberta) Royalties

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act*, 2008) and the "Alberta Royalty Framework", which was implemented in 2010. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable for conventional oil under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices, with the maximum royalty payable for natural gas under the royalty regime set at 36%. Royalty rates for NGL are product specific and range up to 40%.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. The Innovative Energy Technologies Program (the IETP), which is currently in place, has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the *Emerging Resource and Technologies Initiative*). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sand wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" (PTF) applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for "old oil", "new oil" and "third tier oil", and 250 m^3 per month for "fourth tier oil". Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Government of Saskatchewan, the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties. Natural gas liquids and by-products recovered at gas processing plants are not subject to a royalty. Gas liquids, which are produced and measured at the wellhead, are treated as crude oil for royalty purposes.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act*, 2010 with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations, 2012* which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 103 m^3/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas. The current regulatory scheme provides for certain differences with respect to the administration of "fourth tier gas" which is associated gas.

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

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

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

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

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

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% of EOR operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR projects; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

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

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

Land Tenure

In Alberta and Saskatchewan, the Crown predominantly owns rights to petroleum and natural gas. The provincial governments of Alberta and Saskatchewan grant rights to explore for and produce petroleum and natural gas pursuant to Crown leases, licences, and permits for varying terms and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. Private ownership of rights to petroleum and natural gas also exists in Alberta and Saskatchewan in the form of fee simple mineral title to petroleum and natural gas held by individuals or corporations. Rights to explore for and produce petroleum and natural gas on fee simple mineral title lands are granted by leases on such terms and conditions as may be negotiated between lessor and lessee.

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 (both to lessees pursuant to previously issued leases and to Encana pursuant to the Lease Issuance and Administration Agreements). 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, the Provinces of Alberta and Saskatchewan have implemented changes to 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. Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licences. For leases and licences issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or licence. Leases and licences granted prior to January 1, 2009, but continued after that date, are not subject to shallow rights reversion until they continue past their primary term (at which time the application of deep rights reversion occurs).

Other Regulations and Orders

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.

From time to time federal, provincial and other regulatory agencies issue orders which have the ability to disrupt exploration, development and production activities and/or transportation of hydrocarbon products to markets. As at the date of this AIF, the Company is unaware of any such order or disruption which could materially affect the Company's business or financial position, however there is no guarantee that the same could not be issued in the future, and such matters are outside of the Company's control and could negatively impact the Company.

Freehold Mineral Tax

The Freehold Mineral Tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands. It is derived from the *Freehold Mineral Rights Tax Act*. The Freehold Mineral Tax is levied on an annual basis on calendar year production and uses a formula which takes into consideration the amount of production, the hours of production, value of each unit of production, the tax rate, the percentages that the owners hold in the title and the percentages that the title and wells hold in the production entities being taxed. On average, the tax levied is 3% of revenues reported from fee simple mineral title properties.

Although the registered fee simple mineral title owner is responsible for paying the Freehold Mineral Tax, most lease agreements (including those documented pursuant to the Lease Issuance and Administration Agreements) contain a provision which transfers Freehold Mineral Tax payment obligations to the lessee of the mineral rights. However, each private lease agreement with each fee simple mineral title owner will have different provisions that determine payment responsibilities.

RISK FACTORS

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 and the oil and natural gas business generally.

Risks Relating to the Company's Business, Industry and Operating Environment

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 significantly impacted by factors and risks that impact the oil and natural gas industry generally and in particular affect the lessees and/or operators that have or will have arrangements with the Company in respect of the Royalty Properties. In the event that 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 any portion of the Fee Lands or the GORR Lands, these risks would also become the direct risks of the Company in respect of such development. 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

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 retain or 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. The deferral of development or capital projects conducted on the Royalty Properties may delay 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.

Third Party Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. 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 petroleum and natural gas on the Company's properties by these lessees, as well as to acquire additional petroleum 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 acquired pursuant to the Encana Royalty Acquisition and the Range Royalty Acquisition, 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 petroleum 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.

Future oil and natural gas exploration on the Royalty Properties may involve unprofitable efforts from both dry wells and from wells that are productive but do not produce sufficient petroleum substances to return a profit to a third party after drilling, completing, operating and other costs. Completion of a well does not assure 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 shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect a third party's production from the Royalty Properties, which may reduce the Company's revenue.

Reserves Estimates

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 those 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 were estimated by experience and analogy to similar formations. 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, 2014 with a preparation date of February 10, 2015 and, except as may be specifically stated or required by applicable securities laws, has not been updated since that date.

Prices, Markets and Marketing

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 the Royalty Properties.

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 petroleum and natural gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions in the United States, Canada, Asia and Europe, the actions of the Organization of the Petroleum Exporting Countries (OPEC), governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of petroleum 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 Company's 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 petroleum and natural gas development and acquisition 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 have decreased significantly in recent months and are expected to remain volatile in the near future due to market uncertainties over the supply of and the demand for these commodities due to concerns of over supply, the current state of the world economies, OPEC actions, sanctions imposed on certain oil producing nations by other countries and the ongoing credit and liquidity concerns. Volatile crude oil and natural gas prices make it difficult to estimate the value of producing properties for development activities and often cause disruption in the acquisition, divestiture or leasing of petroleum 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.

Gathering and Processing Facilities, Pipeline Systems and Rail

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 rail. The amount of petroleum and natural gas produced and sold from the Royalty Properties is subject to the accessibility, availability, proximity and capacity of these gathering, processing, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, including any restrictions placed on such systems or facilities, 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 produce and to market petroleum and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export petroleum and natural gas. Furthermore, 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 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.

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

The production from the Royalty Properties is processed through facilities 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 materially adversely 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 petroleum 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 petroleum 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 petroleum and natural gas and other aspects of the oil and natural gas industry may also affect the Company.

Management of Growth and Integration

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 pursuant to the Encana Royalty Acquisition and the Range Royalty Acquisition while they were under the management of Encana and Range Royalty, 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 will 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 and financial condition.

Reliance on Key Personnel

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 and financial condition. The Company does not have any key person insurance in effect for the Company. 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 management.

Third Party Credit Risk

The Company may be exposed to third party credit risk through its royalty and contractual arrangements with the third parties on the Royalty Properties, marketers of its petroleum 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.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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 and financial condition. 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, if disposed of, may realize less than what the market may expect for such disposition or their carrying value on the financial statements of the Company.

Title to Assets

Title reviews conducted on petroleum and natural gas producing properties, if any, do not guarantee or certify that an unforeseen 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 previous 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 and financial condition. 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 result in a reduction of the revenue received by the Company.

Capital and Additional Funding Requirements

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 making capital expenditures for the acquisition of additional petroleum 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; 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.

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. 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 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 payment of dividends by the Company is not guaranteed and could fluctuate with the performance of the Company. 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 Facilities 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.

Foreign Exchange Risk on Dividends

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.

Negative Impact of Additional Sales or Issuances of Common Shares

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.

Issuance of Debt

From time to time, the Company may finance its activities (including potential future petroleum 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

Pursuant to the terms and conditions of the Credit Facilities, 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 Facilities and would prevent dividends from being paid to shareholders. The acceleration of the Company's indebtedness under the Credit Facilities may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Credit Facilities 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.

Competition

The oil and natural gas industry is highly competitive in all aspects. The Company competes with numerous other entities to encourage third party development of the Royalty Properties and to acquire additional petroleum 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.

Variations in Foreign Exchange Rates and Interest Rates

The Canadian/United States dollar exchange rate, which fluctuates over time, could 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.

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

From time to time, 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. Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar.

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

Litigation and Aboriginal Claims

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, related to property damage, property tax, land 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 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 and financial condition.

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada, including in the Provinces of Alberta and Saskatchewan. In particular, certain aboriginal groups have challenged title to lands near the Fee Lands. If such claims arose in relation to the Fee Lands, and such claims were successful, it could materially adversely affect the Company's business and financial condition.

Income Taxes

Income tax laws relating to the oil and natural gas industry 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 and deferred taxes payable.

Conflicts of Interest

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.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations, including on exploration, production, pricing, marketing and transportation. Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of petroleum 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 the Freehold Mineral Tax, may occur from time to time in response to economic or political conditions. See "*The Industry*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas or make certain projects on the Company's properties uneconomic, which could materially adversely affect the Company's business and financial condition.

Availability of Drilling Equipment and Access

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

Breach of Confidentiality

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 signed by third parties prior to the disclosure of any confidential information, 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 in 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.

Environmental

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

As a royalty interest holder, the Company believes it has minimal or no direct exposure to environmental claims and regulation and 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 Company relies on the lessee or operators of the Royalty Properties to be in material compliance with current applicable environmental regulations; however, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities associated with the Royalty Properties or otherwise have a material adverse effect on the Company's business and financial condition.

Climate Change

Operations and activities associated with the Royalty Properties emit greenhouse gases 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 in Alberta, Saskatchewan or that may be enacted in other provinces. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. The Government of Canada announced in 2010 that it will seek a 17% reduction in greenhouse gas (GHG) emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding however. 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. The indirect costs of compliance with these regulations could materially adversely affect the Company's business and financial condition. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Company's business and financial condition.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and certain amounts of additives under pressure into rock formations to stimulate petroleum and natural gas production. Specifically, hydraulic fracturing is used to produce commercial quantities of petroleum and natural gas from reservoirs that were previously unproductive or to make existing reservoirs more productive. 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 delay or eliminate the development of certain oil and natural gas resources which are not commercial without the use of hydraulic fracturing on the Royalty Properties. Restrictions on hydraulic fracturing could also reduce the amount of petroleum 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 and financial condition.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby potentially reducing activity levels on the Royalty Properties. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and also to volatility in commodity prices as the demand for natural gas rises during cold winter months and hot summer months.

Geopolitical Risks

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 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.

In addition, 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.

Global Financial Markets

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

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil and other hydrocarbons. 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.

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 23, 2015, 149,328,486 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 for the periods indicated:

Toronto Stock Exchange
Common Shares Trading Range

	High ($/Common Share)	Low ($/Common Share)	Volume Traded
2014			
May (29-31)	37.00	36.25	21,355,532
June	40.00	36.05	9,069,853
July	42.39	38.13	4,563,507
August	40.90	39.29	2,319,931
September	39.14	34.50	11,645,631
October	35.20	31.73	12,410,624
November	37.36	33.81	20,263,516
December	35.36	29.20	27,709,929
2015			
January	30.40	24.20	36,597,034
February (1-20)	31.29	27.36	15,898,851

ESCROWED SECURITIES

To the knowledge of the Company, no securities of the Company are held in escrow.

DIVIDENDS

The Board has established a dividend policy pursuant to which the Company pays a monthly dividend, currently in the amount of $0.10833 per Common Share per month or $1.30 per Common Share on an annualized basis.

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 or declared payable by the Company to its shareholders in the months indicated.

Month of Dividend Payment Date	
2014	
July	$0.1058
August	$0.1058
September	$0.1058
October	$0.1058
November	$0.1058
December	$0.1058
2015	
January	$0.10833
February	$0.10833

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 23, 2015, 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 officers of PrairieSky:

Name, Province and Country of Residence	Principal Occupation	Date of Appointment
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
L. Geoffrey Barlow Calgary, Alberta, Canada	Vice-President, Finance & Chief Financial Officer of the Company	April 11, 2014
Cristina Lopez Calgary, Alberta, Canada	Vice-President, Corporate Development of the Company	September 3, 2014
Michelle Radomski Calgary, Alberta, Canada	Vice President, Land of the Company	December 19, 2014

As at February 23, 2015, the directors and senior officers of PrairieSky, as a group, beneficially own or control, directly or indirectly, 2,631,508 Common Shares or 1.76% of the issued and outstanding Common Shares.

Directors and Executive Officers Biographical Information

The following are brief profiles of each of the executive officers and directors 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 30 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 company, and the lead 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 boards of The Estey Centre for Law and Economics in International Trade and St. Clements School, and is on the Advisory Board of the Edwards School of Business.

Margaret McKenzie

Ms. McKenzie was formerly the Vice President, Finance and Chief Financial Officer of Range 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 Institute of Chartered 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 two private energy companies and Bonavista Energy Corporation, a TSX-listed oil and natural gas 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 by Mr. Phillips 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 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.

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, 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 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.

L. Geoffrey Barlow

Mr. Barlow is the Vice-President, Finance and Chief Financial Officer of the Company and has over 25 years of experience in the oil and natural gas industry, including as a member of executive management for numerous publicly-traded companies. Prior to his appointment as the Vice-President, Finance and Chief Financial Officer of the Company, Mr. Barlow was the Chief Financial Officer and Vice-President, Finance of Chinook Energy Inc., a TSX-listed oil and natural gas company. Prior thereto, Mr. Barlow was the Vice-President and Chief Financial Officer of Husky, a TSX-listed public integrated energy company, and held senior management positions at Renaissance Energy Ltd. Mr. Barlow is a Chartered Accountant and a member of the Institute of Chartered Accountants of Alberta, and holds a Bachelor of Commerce degree from the University of Calgary.

Cristina Lopez

Ms. Lopez is the Vice President, Corporate Development of the Company and has significant experience in financial markets and business development, specializing in oil & gas research over the past 13 years. Prior to joining the company, Ms. Lopez was co-head of Canadian Oil & Gas Equity Research at Macquarie Capital Markets Canada Ltd. During her time as an equity research analyst, Ms. Lopez was charged with primary research coverage of over 35 companies, including royalty trusts, high payout exploration and production companies, small/mid cap domestic producers as well as Latin American based exploration and production companies and was recognized multiple times by Brendan Woods International as a top Analyst. Ms. Lopez is a CFA charterholder and holds a Bachelor of Commerce degree majoring in Finance and a Bachelor of Arts degree from the University of Calgary.

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 Royalty Management Ltd. since October 1, 2010 and prior thereto held leadership roles with Monterey Exploration Ltd., Baytex Energy Corp., Canadian

Occidental Petroleum Ltd. (predecessor to Nexen) and Imperial Oil. 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. None of the directors or executive officers of PrairieSky is as at the date of this AIF, or has been within 10 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, other than Mr. Zawalsky who was formerly a director of Efficient Energy Resources Ltd. (a private electrical generation company) which agreed to the voluntary appointment of a receiver in 2005.

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 10 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 pre-approves all non-audit services to be provided to the Company's by the external auditors. Prior to the commencement of the Company's fiscal year, the audit committee pre-approves expenditures with a dollar limit for services related to consultations as to the accounting or disclosure treatment of transactions, and for expenditures with a dollar limit for services related to taxation matters. The audit committee must pre-approve any costs that exceed these limits.

External Auditor Service Fees[1]

	Year Ended December 31, 2014
Audit fees[2]	$ 130,650
Audit-related fees[3]	$ 15,750
Tax fees	—
All other fees	$ 20,000
Total	$ 166,400

Notes:

(1) External auditor service fees includes fees paid to both predecessor and current auditors.

(2) Audit fees consist of fees for the audit of PrairieSky's annual financial statements, reviews of interim consolidated financial statements for the second and third quarters of the 2014 fiscal year, or services that are normally provided in connection with statutory and regulatory filings or engagements.

(3) Audit-related fees consist of fees 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.

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.

PROMOTER

Encana may be considered a promoter of the Company in that it took the initiative in incorporating and organizing PrairieSky. On May 27, 2014, PrairieSky entered into the Purchase and Sale Agreement with Encana and completed the Encana Royalty Acquisition. In connection with closing of the Encana Royalty Acquisition, PrairieSky entered into the Transition Services Agreement, which terminated December 31, 2014. See "*General Development of the Business*". In connection with the Encana Royalty Acquisition, the Company entered into the Lease Issuance and Administrative Agreements, the Seismic License Agreement and Trust Agreement. See "*Material Contracts*" below.

As of December 31, 2014, Encana holds no Common Shares.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of management of PrairieSky 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

TMX Equity Transfer Services 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 only material contracts entered into by the Company within the most recently completed financial year, or before the most recently completed financial year but which are still in effect, are the following:

- *Lease Issuance and Administrative Agreements*. As part of the Encana Royalty Acquisition and pursuant to the Purchase and Sale Agreement, the Company and Encana entered into the Lease Issuance and Administration Agreements, pursuant to which the Company agreed to issue and deliver within a specified period of time documented leases to Encana as they related to certain Fee Lands. The Lease Issuance and Administration Agreements also established and defined the terms of the leasehold interests that were retained by Encana in certain Fee Lands through established forms of leases applicable to the particular rights. All or portions of Encana's rights and obligations under the Lease Issuance and Administration Agreements are assignable by Encana to third parties.

- *Seismic Licence Agreement*. As part of the Encana Royalty Acquisition pursuant to the Purchase and Sale Agreement, the Company and Encana entered into the Seismic Licence Agreement pursuant to which Encana licensed to the Company certain proprietary seismic interests. The licence granted to the Company under the Seismic Licence Agreement is fully paid, perpetual, irrevocable, royalty-free, non-exclusive and, subject to certain limitations, transferable. The Company has certain rights to sub-license the seismic data to third parties in connection with its business operations, including transactions involving the Royalty Properties acquired by the Company under the Purchase and Sale Agreement. The Company is prohibited from sublicensing for financial consideration.

- *Trust Agreement*. As part of the Encana Royalty Acquisition pursuant to the Purchase and Sale Agreement, the Company and Encana entered into the Trust Agreement to provide for any registered title to the Fee Lands or other assets acquired pursuant to the Encana Royalty Acquisition that were not validly conveyed to the Company at the time of completion, including as a result of the required filings not having been completed at the appropriate land titles office. The Trust Agreement provides that Encana is deemed to hold title to such Fee Lands in trust as bare trustee, agent and nominee for the benefit of the Company, and the Company is deemed to be the beneficial owner of all such Fee Lands from and after completion of the Encana Royalty Acquisition.

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 evaluators.

Interest of Experts

KPMG LLP is the auditor of the Company and is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants, Alberta. As at the date hereof, the designated professionals (as defined in NI 51-102) of GLJ, as a group, 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 or any of our associate or affiliate entities.

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, 2014 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 Corporation, will be contained in the Information Circular – Management Proxy Statement of the Corporation to which relates to the Annual Meeting of Shareholders to be held on April 28, 2015.

For copies of our 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 1900, 411 – 1st Street S.E.
Calgary, Alberta T2G 4Y5
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, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2014, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation 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	Corporate Summary February 10, 2015	Canada	-	924,484	-	924,484

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

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

GLJ Petroleum Consultants

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

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 10, 2015

"ORIGINALLY SIGNED BY"

Chad P. Lemke, P. Eng.
Manager, Engineering

GLJ Petroleum Consultants

APPENDIX B

Form 51-101F3

Report of Management and Directors on Oil and Gas Disclosure

Management of PrairieSky Royalty Ltd. (the "**Company**") is 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, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014 estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report 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 Form 51-101F2, which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

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

(signed) "*Cristina Lopez"*
Cristina Lopez
Vice President, Corporate Development

(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 23rd day of February, 2015.

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 Company's compliance with legal and regulatory requirements; 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 managerial 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 an Committee member receives from the Company.

Committee members shall not simultaneously serve on the audit committees of more than two other public companies, unless the Board first determines that such simultaneous service will not impair the ability of the relevant members to effectively serve on the Committee, and required public disclosure is made.

The Board Chairman shall be a non-voting member of the Committee (see discussion under the heading "Quorum" below for further details). 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.

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 report 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 financial statements and related footnotes, including significant issues regarding accounting principles, practices and significant management estimates and judgments, including any significant changes in the Company's selection or application of accounting principles, any major issues as to the adequacy of the Company's internal controls and any special steps adopted in light of material control deficiencies;

    (b) Management's Discussion and Analysis;

    (c) A review of the use of off-balance sheet financing, including management's risk assessment and adequacy of disclosure;

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

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

    (f) 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

    (g) 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. Review and formally recommend approval to the Board of the Company's:

    (a) Year-end audited financial statements. Such review shall include discussions with management and the external auditors as to:

        (i) The accounting policies of the Company and any changes thereto;

        (ii) The effect of significant judgments, accruals and estimates;

        (iii) The manner of presentation of significant accounting items; and

(iv) The consistency of disclosure;

(b) Management's Discussion and Analysis;

(c) Annual Information Form as to financial information;

(d) Business acquisition reports and material change reports containing financial information; and

(e) Prospectuses and information circulars as to financial information.

The review shall include a report from the external auditors about the quality of the most critical accounting principles upon which the Company's financial status depends, and which involve the most complex, subjective or significant judgmental decisions or assessments.

Quarterly Financial Statements

3. Review with management and the external auditors and either approve (such approval to include the authorization for public release) 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 principles.

Other Financial Filings and Public Documents

4. 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 earnings 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 shall periodically assess the adequacy of such review.

Internal Control Environment

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

6. 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.

7. Review significant findings prepared by the external auditors together with management's responses.

8. 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. The Committee will assess the coordination of audit effort to assure completeness of coverage and the effective use of audit resources. Any significant recommendations made by the auditors for the strengthening of internal controls shall be reviewed and discussed with management.

Other Review Items

9. Review policies and procedures with respect to officers' and directors' expense accounts and perquisites, including their use of corporate assets, and consider the results of any review of these areas by the external auditors.

10. Review all related party transactions between the Company and any officers or directors, including affiliations of any officers or directors.

11. Review with legal counsel of the Company and the external auditors the results of their review of the Company's monitoring compliance with each of the Company's business code of conduct and applicable legal requirements.

12. Review legal and regulatory matters, including correspondence with regulators and governmental agencies, which may have a material impact on the interim or annual financial statements, related corporation compliance policies, and programs and reports received from regulators or governmental agencies.

13. Review policies and practices with respect to off-balance sheet transactions and trading and hedging activities, if any, and consider the results of any review of these areas by the external auditors.

14. Ensure that the Company's presentations on reserves have been reviewed with the Reserves Committee of the Board.

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

16. 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.

17. 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.

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. Review and discuss a report from the external auditors at least quarterly regarding:

    (a) All critical accounting policies and practices to be used;

    (b) All alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with management, including the ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditors; and

    (c) Other material written communications between the external auditors and management, such as any management letter or schedule of unadjusted differences.

22. 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) To the extent contemplated in the following paragraph, all relationships between the external auditors and the Company.

23. 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, including, without limitation, (i) receiving and reviewing, as part of the report described in the preceding paragraph, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Company and its affiliates, (ii) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors, and (iii) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence.

24. Review and evaluate:

    (a) The external auditors' 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 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;

    (d) Any other related audit engagement matters; and

    (e) The engagement of the external auditors to perform non-audit services, together with the fees therefor, and the impact thereof, on the independence of the external auditors.

25. Upon reviewing and discussing the information provided to the Committee in accordance with paragraphs 21 through 24 in this section, evaluate the external auditors' qualifications, performance and independence, including whether or not the external auditors' quality controls are adequate and the provision of permitted non-audit services is compatible with maintaining auditor independence, taking into account the opinions of management and the head of internal audit. The Committee shall present its conclusions with respect to the external auditors to the Board.

26. 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.

27. Review and set clear hiring policies for the Company's hiring of partners, employees and former partners and employees of the present and any former external auditors.

28. Consider with management and the external auditors the rationale for employing audit firms other than the principal external auditors.

29. 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

30. 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).

31. 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.

32. If the pre-approvals contemplated in paragraphs 30 and 31 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.

33. 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 30 through 32. The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

34. The Committee may establish policies and procedures for the pre-approvals described in paragraphs 30 and 31, 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

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

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

37. 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 the carrying out of its duties. The Committee shall have the authority to set and pay compensation for any such advisors.

38. The Company shall provide for appropriate funding, as determined by the Committee in its capacity as a committee of the Board, for payment (i) of compensation to the external auditors for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Company, (ii) of compensation to any advisors employed by the Committee and (iii) of ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties.

39. The Committee shall have the authority to communicate directly with the external auditors.

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

41. The Committee's performance shall be evaluated annually by the Board.

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

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

Miscellaneous

This mandate is subject to the terms of the governance agreement between the Company and Encana Corporation, as amended from time to time (the "**Governance Agreement**"), including with respect to the reporting obligations of the Company and the Committee contained therein. Where a conflict exists between the provisions of this Mandate and the terms of the Governance Agreement, the terms of the Governance Agreement shall prevail.

Effective: April 11, 2014