PRAIRIESKY
ROYALTY LTD

# 2016 ANNUAL INFORMATION FORM

**February 27, 2017**

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## ADVISORIES

### Cautionary Statement Regarding Forward-Looking Information and Statements

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

- the Company's objective to generate free cash flow and growth for its shareholders at a relatively low risk and low cost to the Company, and the proposed manner of achieving this objective;
- the Company's strategy with respect to future acquisitions;
- the Company's dividend policy, the funding of such dividends, the amounts expected to be paid under that policy in the future and the anticipated timing of payment of such dividends;
- the Company's business and growth strategy and the expectation that the Company will be successful in strategically seeking additional 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 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 of many of the Royalty Properties;

- the timing and amount of capital expenditure programs and well drilling activity by third parties on the Royalty Properties;
- the expectation of not receiving any future royalty revenue from its royalty interest in the third party operated Highvale coal mine;
- anticipated future crude oil, natural gas and NGL prices and currency, exchange and interest rates;
- supply and demand for 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) and the operators and working interest owners on the Royalty Properties;
- risks and 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 on the Fee Lands and the operators and working interest owners on the Royalty Properties;
- competition for, among other things, third party capital and acquisitions of reserves, additional 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 (including deductions from PrairieSky's royalty share of production) 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;
- breaches or failure of information systems and security (including risks associated with cyber-attacks);
- a decrease or elimination of the payment of dividends by the Company as a result of a Board determination or restrictions under applicable agreements or corporate laws;
- general economic, market and business conditions;
- changes in tax or environmental laws or royalty or incentive programs relating to the oil and natural gas industry; and
- the other factors discussed under “Risk Factors” herein.

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

- the ability of the lessees on the Fee Lands and the operators and working interest owners on the Royalty Properties to maintain or increase production and reserves from these properties;
- the ability and willingness of the lessees on the Fee Lands and working interest owners on the Royalty Properties to comply with, and the Company to enforce, lease terms and contractual provisions, as applicable, in order to receive payments in respect of the Royalty Properties;
- the ability of the lessees on the Fee Lands or the operators and working interest owners on the Royalty Properties to operate in a safe, efficient and effective manner;
- the timely receipt of any required regulatory approvals by lessees on the Fee Lands or the operators and working interest owners on the Royalty Properties;
- the willingness and financial capability of the lessees on the Fee Lands and working interest owners on the GORR Lands (as defined herein) to continue to develop and invest additional capital in the Royalty Properties;
- the ability of the lessees on the Fee Lands and working interest owners on the Royalty Properties to obtain financing on acceptable terms to fund exploration and development capital expenditures;
- field production rates, decline rates and the well performance and characteristics of the Royalty Properties;
- the ability to replace and increase crude oil, natural gas and NGL reserves and production associated with the Royalty Properties through third party development and acquisitions;
- the timing, cost and ability of third parties to access, maintain or expand necessary facilities and/or secure adequate product transportation and storage;
- the ability of the operators of the properties in which the Company has a royalty interest in, to successfully market their respective 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 crude oil and natural gas properties; and
- future crude oil, natural gas and NGL prices and currency, exchange and interest rates.

Statements relating to reserves are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this AIF are expressly qualified by this cautionary statement.

### Conversion of Natural Gas to Barrels of Oil Equivalent

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

### Presentation of Oil and Natural Gas Reserves and Production Information

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

All acreage information with respect to the Fee Lands, GRT Lands (as defined herein) and GORR Lands in this AIF has been presented on a gross acre basis. For the Fee Lands, gross acres 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 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;

*CNRL* means Canadian Natural Resources Limited;

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

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

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

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

*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;

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

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

*Encana* means Encana Corporation;

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

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

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

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

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

*GLJ Price Forecast* means the GLJ commodity price forecast as of January 1, 2017;

*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, 2016, and a preparation date of February 10, 2017;

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

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

*gross* means: (i) in relation to the Company's interest in production or reserves, its Lessor Interests, GRT Interests, GORR Interests in production or reserves, after deduction of royalty obligations payable to other parties, if any; (ii) in relation to wells, the total number of wells in which the Company has an interest; and (iii) in relation to properties, the total area in which the Company has an interest;

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

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

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

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

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

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

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

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

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

*Pengrowth* means Pengrowth Energy Corporation;

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

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

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

*Range GP* means Range Royalty Management Ltd.;

*Range Royalty* means Range Royalty Limited Partnership;

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

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

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

*SAGD* means steam assisted gravity drainage;

*SEDAR* means the System for Electronic Document Analysis and Retrieval;

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

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

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

*shareholder* means a holder of Common Shares;

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

*subsidiary* has the meaning ascribed thereto in the ABCA;

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

*TSX* means the Toronto Stock Exchange.

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## ABBREVIATIONS AND CONVERSIONS

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

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

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

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

## CORPORATE STRUCTURE

### General

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

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

On December 19, 2014, the Company acquired all of the issued and outstanding units of Range Royalty and all of the outstanding shares of Range GP in exchange for the issuance of approximately 19.3 million Common Shares. As part of the Range Royalty Acquisition and through a series of transactions: (i) Range Royalty was wound up and distributed its assets to PrairieSky; and (ii) PrairieSky amalgamated with Range GP and continued under the name "PrairieSky Royalty Ltd.". PrairieSky is the legal successor in interest to Range Royalty and Range GP.

As of December 31, 2016, and the date hereof, PrairieSky has no material subsidiaries.

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

## GENERAL DEVELOPMENT OF THE BUSINESS

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

### Year Ended December 31, 2016

#### *The Q4 2016 Royalty Acquisitions*

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

#### *The Pengrowth GORR Acquisition*

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

*Information*" contained herein does not contain any reserves or other information attributable to the Pengrowth GORR Acquisition given the effective and closing dates occurred subsequent to December 31, 2016.

### *The December 2016 Offering*

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

## Year Ended December 31, 2015

### *The July 2015 Offering*

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

### *The December 2015 Private Placement*

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

### *The CNRL Royalty Acquisition*

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

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

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

## 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, NGL and certain other mineral rights located predominantly in central and southern Alberta; (ii) lessor interests in and to leases issued in respect of certain Fee Lands; (iii) royalty interests, including overriding royalty interests, gross overriding royalty interests and production payments on lands located predominantly in Alberta; (iv) the Seismic Licence; and (v) certain other related assets as set forth in the Encana 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 Encana 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.

#### *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.

#### *The September 2014 Secondary Offering*

On September 26, 2014, PrairieSky and Encana completed 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 2014 Secondary Offering. Following the closing of the September 2014 Secondary Offering, Encana no longer held any interest in PrairieSky.

#### *Range Royalty Acquisition*

On December 19, 2014, PrairieSky completed 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 the 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

The Company did not complete any acquisitions that would be considered significant pursuant to NI 51-102 during the year ended December 31, 2016.

## BUSINESS OF THE COMPANY

### General

The Company currently has one of the largest independently-owned portfolios of fee simple mineral title and oil and gas royalty interests in Canada. The Company is focused on encouraging third parties to actively develop the Royalty Properties while strategically seeking additional petroleum and natural gas royalty assets that provide the Company with medium-term to long-term value enhancement potential, including the acquisition of lands at Crown land sales for purposes of complementing the Company's fee title land base and pursuing prospective farmout strategies. The Company does not directly conduct operations to explore for, develop or produce petroleum or natural gas; rather, third party development of the Royalty Properties provides the Company with royalty revenues as petroleum, natural gas and associated substances are produced from such properties. The Company's costs are primarily production and mineral taxes, 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 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 predominantly 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 currently takes certain petroleum and natural gas royalty volumes in-kind.

### *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 8.9 million acres of Fee Lands (including coal only titles). For the year ended December 31, 2016, the Lessor Interests provided approximately 79% of the total royalty revenue of the Company, of which royalty revenue derived from production of liquids (crude oil and NGL) and natural gas accounted for approximately 80% and 20%, respectively.

For the year ended December 31, 2016, average net production associated with the Lessor Interests was approximately 16,311 boe/d, with approximately 45.5 MMcfpd of natural gas production, approximately 7,017 bbls/d of oil production and approximately 1,711 bbls/d of NGL production, generating total royalty revenue of approximately $158.9 million. In addition, in 2016, the lease rental income associated with the Lessor Interests was approximately $8.5 million.

### *GORR Interests*

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

The granting of a GORR Interest can arise in many instances, including as a result of: (i) the Company farming out working interest rights to another company in exchange for retaining a GORR Interest on production from wells drilled under the farmout agreement; (ii) the Company providing capital in exchange for granting of a GORR Interest or converting a participating interest in a joint venture relationship into a GORR Interest; (iii) the Company, as owner of certain Fee Lands that are in a checkerboard 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 6.3 million acres of GORR Lands, substantially all of which are associated with Crown lands. During the year ended December 31, 2016, average net production associated with the GORR Lands was approximately 6,997 boe/d, with approximately 29.2 MMcfpd of natural gas production, approximately 1,438 bbls/d of oil production and approximately 692 bbls/d of NGL production, generating total royalty revenue of approximately $42.5 million. In 2016, the GORR Interests provided approximately 21% of the total royalty revenue of PrairieSky.

### *GRT Interests*

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

### *Crown Interest Lands*

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

## Specialized Skill and Knowledge

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

### Reorganizations

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

### Personnel

As of December 31, 2016, the Company had 66 full time employees and 3 part time employees.

### Cyclical and Seasonal Nature of Industry

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

The level of activity in the Canadian petroleum and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain crude oil and natural gas producing 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 working interest owners and/or the operators or the curtailment of production which may have a material adverse effect on the Company's business and financial condition.

### Competitive Conditions

PrairieSky is a member of the petroleum industry, which is highly competitive at all levels. PrairieSky competes with other companies for all of its business inputs, access to commodity markets, acquisition opportunities, available capital and staffing. PrairieSky strives to be competitive by maintaining a strong financial condition and by focusing on building and maintaining strong relationships with high quality lessees, operating a well established compliance program and identifying 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 prepared by GLJ with an effective date of December 31, 2016, and a preparation date of February 10, 2017, as set forth in the GLJ Report. The GLJ Report evaluated, as at December 31, 2016, the crude oil, natural gas and NGL reserves associated with the Royalty Properties. The tables below summarize the reserves and the net present value of future net revenue attributable to the reserves as evaluated in the GLJ Report based on the GLJ Price Forecast, cost assumptions and supplied operating expenses.

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

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

In preparing the GLJ Report, GLJ relied on certain information provided by third parties associated with the Royalty Properties, which included working and net revenue interest data, public data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, financial data and future development and operating plans for the Royalty Properties, as applicable. Other engineering, historical production, geological or economic data required to conduct the evaluations and upon which the GLJ Report are 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 evaluations, from all sources, was accepted by GLJ as represented.

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

GLJ was engaged by the Company to provide an evaluation of proved and probable reserves. All of the reserves associated with the Royalty Properties are located in the provinces of Alberta, Saskatchewan, Manitoba and British Columbia. 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, 2016
## Forecast Prices and Costs[1]

### *Summary of Reserves*

| Reserves Category | Light & Medium Crude Oil (Combined) Gross (2)(4) (Mbbl) | Light & Medium Crude Oil (Combined) Net (3)(4) (Mbbl) | Heavy Crude Oil Gross (2)(4) (Mbbl) | Heavy Crude Oil Net (3)(4) (Mbbl) | Tight Oil Gross (2)(4) (Mbbl) | Tight Oil Net (3)(4) (Mbbl) | Bitumen Gross (2)(4) (Mbbl) | Bitumen Net (3)(4) (Mbbl) | Conventional Natural Gas Gross (2)(4) (MMcf) | Conventional Natural Gas Net (3)(4) (MMcf) |
|---|---|---|---|---|---|---|---|---|---|---|
| Proved | | | | | | | | | | |
| Developed Producing | - | 8,496 | - | 1,754 | - | 545 | - | 244 | - | 86,021 |
| Developed Non-Producing | - | 350 | - | 13 | - | - | - | - | - | 1,897 |
| Undeveloped | - | - | - | - | - | - | - | - | - | - |
| Total Proved | - | 8,846 | - | 1,766 | - | 545 | - | 244 | - | 87,918 |
| Total Probable | - | 2,831 | - | 548 | - | 206 | - | 65 | - | 25,056 |
| Total Proved Plus Probable | - | 11,677 | - | 2,314 | - | 751 | - | 309 | - | 112,974 |

| Reserves Category | Shale Gas Gross (2)(4) (MMcf) | Shale Gas Net (3)(4) (MMcf) | Coal Bed Methane Gross (2)(4) (MMcf) | Coal Bed Methane Net (3)(4) (MMcf) | Natural Gas Liquids Gross (2)(4) (Mbbl) | Natural Gas Liquids Net (3)(4) (Mbbl) | Oil Equivalent Gross (2)(4) (Mboe) | Oil Equivalent Net (3)(4) (Mboe) |
|---|---|---|---|---|---|---|---|---|
| Proved | | | | | | | | |
| Developed Producing | - | 9,436 | - | 33,477 | - | 3,675 | - | 36,188 |
| Developed Non-Producing | - | 573 | - | - | - | 89 | - | 863 |
| Undeveloped | - | - | - | - | - | - | - | - |
| Total Proved | - | 9,920 | - | 33,477 | - | 3,764 | - | 37,051 |
| Total Probable | - | 2,912 | - | 5,776 | - | 1,099 | - | 10,373 |
| Total Proved Plus Probable | - | 12,832 | - | 39,253 | - | 4,863 | - | 47,423 |

** Numbers may not add due to rounding.-*

Notes:

(1) Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions — Forecast Prices and Costs*".

(2) Gross reserves represents the Company's interest in reserves before deduction of royalties and without including any royalty interests.

(3) Net reserves represents the Company's interest in reserves after deduction of royalty obligations plus the Company's royalty interests in reserves.

(4) The Company differs from typical oil and natural gas producers in that all of its interests in reserves are royalty interests with no associated working interests. As a result, there are no gross reserves associated with the Royalty Properties, which may hinder comparison of the Company's reserves with others in the oil and natural gas industry.

### *Summary of Net Present Values of Future Net Revenue*

| Reserves Category | Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/year)(1) | | | | | Unit Value Before Income Tax Discounted at 10%/year(2) | |
|---|---|---|---|---|---|---|---|
| | 0% | 5% | 10% | 15% | 20% | | |
| | *M$* | *M$* | *M$* | *M$* | *M$* | *$/boe* | *$/Mcfe* |
| Proved | | | | | | | |
| Developed Producing | 1,356,206 | 1,020,891 | 826,661 | 699,941 | 610,720 | 22.84 | 3.81 |
| Developed Non-Producing | 35,478 | 27,374 | 22,829 | 19,933 | 17,913 | 26.45 | 4.41 |
| Undeveloped | - | - | - | - | - | - | - |
| Total Proved | 1,391,684 | 1,048,265 | 849,489 | 719,874 | 628,634 | 22.93 | 3.82 |
| Total Probable | 510,219 | 272,918 | 174,890 | 124,636 | 95,106 | 16.86 | 2.81 |
| Total Proved Plus Probable | 1,901,903 | 1,321,183 | 1,024,379 | 844,509 | 723,740 | 21.60 | 3.60 |

** Numbers may not add due to rounding.*

| Reserves Category | Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/year)(1) | | | | |
|---|---|---|---|---|---|
| | 0% | 5% | 10% | 15% | 20% |
| | *M$* | *M$* | *M$* | *M$* | *M$* |
| Proved | | | | | |
| Developed Producing | 1,327,308 | 993,773 | 801,067 | 675,671 | 587,558 |
| Developed Non-Producing | 29,229 | 21,728 | 17,665 | 15,165 | 13,472 |
| Undeveloped | - | - | - | - | - |
| Total Proved | 1,356,537 | 1,015,501 | 818,732 | 690,835 | 601,030 |
| Total Probable | 423,077 | 217,945 | 135,924 | 95,071 | 71,615 |
| Total Proved Plus Probable | 1,779,614 | 1,233,446 | 954,657 | 785,906 | 672,645 |

** Numbers may not add due to rounding.*

Note:

(1) Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions — Forecast Prices and Costs*".

(2) Unit values are based on Company Net Reserves.

### *Additional Information Concerning Future Net Revenue (Undiscounted) as of December 31, 2016(1)*

| Reserves Category | Revenue | Royalties(2) | Operating Costs(3) | Capital Development Costs(3) | Aband. & Recl. Costs(3) | Future Net Revenue Before Income Taxes | Income Taxes | Future Net Revenue After Income Taxes |
|---|---|---|---|---|---|---|---|---|
| | *M$* | *M$* | *M$* | *M$* | *M$* | *M$* | *M$* | *M$* |
| Proved | | | | | | | | |
| Developed Producing | 1,376,962 | 20,756 | - | - | - | 1,356,206 | 28,897 | 1,327,308 |
| Developed Non-Producing | 37,426 | 1,948 | - | - | - | 35,478 | 6,249 | 29,229 |
| Undeveloped | - | - | - | - | - | - | - | - |
| Total Proved | 1,414,388 | 22,704 | - | - | - | 1,391,684 | 35,146 | 1,356,537 |
| Total Probable | 518,762 | 8,543 | - | - | - | 510,219 | 87,142 | 423,077 |
| Total Proved Plus Probable | 1,933,150 | 31,247 | - | - | - | 1,901,903 | 122,289 | 1,779,614 |

** Numbers may not add due to rounding.*

Notes:

(1) Future net revenue estimates were calculated using the pricing assumptions set forth below under the heading "*Pricing Assumptions — Forecast Prices and Costs*".
(2) Production and mineral taxes payable.
(3) No operating, development 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 Type as of December 31, 2016 – Forecast Prices and Costs*

| | Future Net Revenue Before Income Taxes(1)(4) (Discounted at 10% per year) | | |
|---|---|---|---|
| | **M$** | **$/boe** | **$/Mcfe** |
| Proved Producing | | | |
| Light Crude Oil & Medium Crude Oil (combined)(2) | 417,180 | 37.50 | 6.25 |
| Heavy Crude Oil(2) | 61,374 | 33.79 | 5.63 |
| Tight Oil2) | 24,069 | 45.10 | 7.52 |
| Bitumen | 7,460 | 30.56 | 5.09 |
| Conventional Natural Gas(3) | 218,010 | 14.61 | 2.43 |
| Shale Gas(3) | 21,917 | 11.66 | 1.94 |
| Coal Bed Methane | 76,652 | 13.53 | 2.25 |
| Total Proved Producing | 826,661 | 22.84 | 3.81 |
| Total Proved | | | |
| Light Crude Oil & Medium Crude Oil (combined)(2) | 433,853 | 37.50 | 6.25 |
| Heavy Crude Oil(2) | 61,796 | 33.78 | 5.63 |
| Tight Oil2) | 24,069 | 45.10 | 7.52 |
| Bitumen | 7,460 | 30.56 | 5.09 |
| Conventional Natural Gas(3) | 222,403 | 14.61 | 2.44 |
| Shale Gas(3) | 23,255 | 11.68 | 1.95 |
| Coal Bed Methane | 76,652 | 13.53 | 2.25 |
| Total Proved | 849,489 | 22.93 | 3.82 |
| Total Proved Plus Probable | | | |
| Light Crude Oil & Medium Crude Oil (combined)(2) | 532,800 | 34.73 | 5.79 |
| Heavy Crude Oil(2) | 76,150 | 31.75 | 5.29 |
| Tight Oil2) | 30,111 | 40.94 | 6.82 |
| Bitumen | 9,240 | 29.91 | 4.99 |
| Conventional Natural Gas(3) | 263,364 | 13.57 | 2.26 |
| Shale Gas(3) | 27,030 | 10.48 | 1.75 |
| Coal Bed Methane | 85,683 | 12.88 | 2.15 |
| Total Proved Plus Probable | 1,024,379 | 21.60 | 3.60 |

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

For future net revenue of the total proved reserves, discounted at 10%, 62% of the revenue is from combined crude oil and 38% is from combined natural gas. For the total proved plus probable reserves, 63% of the revenue is from combined crude oil and 37% is from combined natural gas.

## Notes and Definitions

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

### *Reserve Categories*

The determination of crude oil, bitumen, 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 then current pricing, inflation rate and exchange rate assumptions based on the GLJ Price Forecast (2017-01) in estimating reserves data using forecast prices and costs.

| | Crude Oil | | | | | |
|---|---|---|---|---|---|---|
| **Year** | **Edmonton Light[1]** | **Hardisty Bow River[2]** | **Hardisty WCS[3]** | **Hardisty Heavy Oil[4]** | **Cromer Light Sour[5]** | **Exchange Rate[6]** |
| | ***($/bbl)*** | ***($/bbl)*** | ***($/bbl)*** | ***($/bbl)*** | ***($/bbl)*** | ***($US/$Cdn)*** |
| 2017 | 69.33 | 54.02 | 53.32 | 46.69 | 67.95 | 0.750 |
| 2018 | 72.26 | 57.52 | 56.79 | 50.40 | 70.81 | 0.775 |
| 2019 | 75.00 | 62.02 | 61.27 | 55.03 | 73.50 | 0.800 |
| 2020 | 76.36 | 63.76 | 63.00 | 56.96 | 74.84 | 0.825 |
| 2021 | 78.82 | 66.68 | 65.90 | 59.95 | 77.25 | 0.850 |
| 2022-2026 | 82.35-95.61 | 70.25-84.43 | 69.42-83.47 | 63.43-77.54 | 80.71-93.70 | 0.850 |
| Thereafter | +2%/year | +2%/year | +2%/year | +2%/year | +2%/year | 0.850 |

| | Natural Gas | NGL[7] | | | | |
|---|---|---|---|---|---|---|
| Year | Alberta AECO Spot Prices | Ethanes | Propanes | Butanes | Pentane Plus | Inflation Rate[8] |
| | *($/MMbtu)* | *($/bbl)* | *($/bbl)* | *($/bbl)* | *($/bbl)* | *(%/year)* |
| 2017 | 3.46 | 11.15 | 28.43 | 49.92 | 72.11 | 2 |
| 2018 | 3.10 | 9.92 | 26.74 | 54.19 | 74.79 | 2 |
| 2019 | 3.27 | 10.52 | 26.25 | 56.25 | 78.75 | 2 |
| 2020 | 3.49 | 11.27 | 26.73 | 57.27 | 79.80 | 2 |
| 2021 | 3.67 | 11.87 | 27.59 | 59.12 | 82.37 | 2 |
| 2022-2026 | 3.86-4.32 | 12.54-14.13 | 28.82-33.46 | 61.76-71.71 | 86.06-99.91 | 2 |
| Thereafter | +2%/year | +2%/year | +2%/year | +2%/year | +2%/year | +2%/year |

Notes:
(1) Edmonton Light Sweet 40° API/0.3% sulphur
(2) Hardisty Bow River Stream Quality
(3) Hardisty Western Canadian Select Stream Quality
(4) Hardisty Heavy Oil 12º API
(5) Cromer Light Sour 35º API/1.2% sulphur
(6) The exchange rates used to generate Canadian benchmark reference prices in this table.
(7) Edmonton Natural Gas Liquids
(8) Default cost inflation rate

During 2016, the historical weighted average prices realized in respect of the production associated with the Royalty Properties were $1.65/Mcf for natural gas, $44.22/bbl for total crude oil and $22.01/bbl for NGL.

## Reserves Reconciliation

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

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

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

| | Light Crude Oil and Medium Crude Oil (combined) | | | Heavy Crude Oil | | |
|---|---|---|---|---|---|---|
| | **Proved** | **Probable** | **Proved Plus Probable** | **Proved** | **Probable** | **Proved Plus Probable** |
| | ***(Mbbl)*** | ***(Mbbl)*** | ***(Mbbl)*** | ***(Mbbl)*** | ***(Mbbl)*** | ***(Mbbl)*** |
| December 31, 2015[(1)] | 9,401 | 2,480 | 11,881 | 1,652 | 425 | 2,076 |
| Product Type Transfers[(2)] | - | - | - | (127) | (47) | (175) |
| Adjusted December 31, 2015 | 9,401 | 2,480 | 11,881 | 1,524 | 377 | 1,902 |
| Discoveries | - | - | - | - | - | - |
| Extensions & Improved Recovery | 1,004 | 217 | 1,221 | 16 | 6 | 22 |
| Technical Revisions | 731 | 71 | 802 | (223) | (71) | (294) |
| Acquisitions | 223 | 64 | 287 | 702 | 234 | 936 |
| Dispositions | - | - | - | - | - | - |
| Economic Factors | - | - | - | - | - | - |
| Production | (2,507) | - | (2,507) | (260) | - | (260) |
| **December 31, 2016[(3)]** | 8,852 | 2,832 | 11,685 | 1,759 | 547 | 2,306 |

| | Tight Oil | | | Bitumen | | |
|---|---|---|---|---|---|---|
| | **Proved** | **Probable** | **Proved Plus Probable** | **Proved** | **Probable** | **Proved Plus Probable** |
| | ***(Mbbl)*** | ***(Mbbl)*** | ***(Mbbl)*** | ***(Mbbl)*** | ***(Mbbl)*** | ***(Mbbl)*** |
| December 31, 2015[(1)] | 1,023 | 446 | 1,469 | - | - | - |
| Product Type Transfers[(2)] | - | - | - | 127 | 47 | 175 |
| Adjusted December 31, 2015 | 1,023 | 446 | 1,469 | 127 | 47 | 175 |
| Discoveries | - | - | - | - | - | - |
| Extensions & Improved Recovery | 89 | 27 | 116 | - | - | - |
| Technical Revisions | (331) | (267) | (598) | 206 | 17 | 223 |
| Acquisitions | 2 | - | 3 | - | - | - |
| Dispositions | - | - | - | - | - | - |
| Economic Factors | - | - | - | - | - | - |
| Production | (238) | - | (238) | (89) | - | (89) |
| **December 31, 2016[(3)]** | 546 | 206 | 752 | 244 | 65 | 309 |

| | Conventional Natural Gas | | | Shale Gas | | |
|---|---|---|---|---|---|---|
| | **Proved** | **Probable** | **Proved Plus Probable** | **Proved** | **Probable** | **Proved Plus Probable** |
| | ***(MMcf)*** | ***(MMcf)*** | ***(MMcf)*** | ***(MMcf)*** | ***(MMcf)*** | ***(MMcf)*** |
| December 31, 2015[(1)] | 92,624 | 25,676 | 118,300 | 702 | 227 | 929 |
| Product Type Transfers[(2)] | (4,012) | (1,184) | (5,196) | 4,012 | 1,184 | 5,196 |
| Adjusted December 31, 2015 | 88,612 | 24,493 | 113,105 | 4,713 | 1,411 | 6,124 |
| Discoveries | - | - | - | - | - | - |
| Extensions & Improved Recovery | 6,336 | 1,822 | 8,158 | 5,670 | 892 | 6,562 |
| Technical Revisions | 3,199 | (4,115) | (916) | 1,354 | 594 | 1,948 |
| Acquisitions | 9,215 | 2,857 | 12,072 | 46 | 16 | 61 |
| Dispositions | - | - | - | - | - | - |
| Economic Factors | - | - | - | - | - | - |
| Production | (19,444) | - | (19,444) | (1,863) | - | (1,863) |
| **December 31, 2016[(3)]** | 87,918 | 25,056 | 112,974 | 9,920 | 2,912 | 12,832 |

| | Coal Bed Methane | | | Natural Gas Liquids | | |
|---|---|---|---|---|---|---|
| | **Proved** | **Probable** | **Proved Plus Probable** | **Proved** | **Probable** | **Proved Plus Probable** |
| | ***(MMcf)*** | ***(MMcf)*** | ***(MMcf)*** | ***(Mbbl)*** | ***(Mbbl)*** | ***(Mbbl)*** |
| December 31, 2015(1) | 35,239 | 10,351 | 45,590 | 2,966 | 791 | 3,756 |
| Product Type Transfers(2) | - | - | - | - | - | - |
| Adjusted December 31, 2015 | 35,239 | 10,351 | 45,590 | 2,966 | 791 | 3,756 |
| Discoveries | - | - | - | - | - | - |
| Extensions & Improved Recovery | 7 | 1 | 8 | 418 | 98 | 516 |
| Technical Revisions | 4,194 | (4,593) | (399) | 1,224 | 187 | 1,411 |
| Acquisitions | 69 | 18 | 87 | 36 | 23 | 59 |
| Dispositions | - | - | - | - | - | - |
| Economic Factors | - | - | - | - | - | - |
| Production | (6,033) | - | (6,033) | (879) | - | (879) |
| **December 31, 2016(3)** | 33,477 | 5,776 | 39,253 | 3,764 | 1,099 | 4,863 |

| | Oil Equivalent | | |
|---|---|---|---|
| | **Proved** | **Probable** | **Proved Plus Probable** |
| | ***(Mboe)*** | ***(Mboe)*** | ***(Mboe)*** |
| December 31, 2015(1) | 36,469 | 10,183 | 46,653 |
| Product Type Transfers(2) | - | - | - |
| Adjusted December 31, 2015 | 36,469 | 10,183 | 46,653 |
| Discoveries | - | - | - |
| Extensions & Improved Recovery | 3,529 | 801 | 4,330 |
| Technical Revisions | 3,065 | (1,415) | 1,650 |
| Acquisitions | 2,518 | 803 | 3,321 |
| Dispositions | - | - | - |
| Economic Factors | - | - | - |
| Production | (8,531) | - | (8,531) |
| **December 31, 2016(2)** | 37,051 | 10,373 | 47,423 |

Notes:
(1) December 31, 2015 opening balance from the Company reserve reports prepared by GLJ and Sproule Associates Limited.
(2) Product Type Transfers to align material changes in bitumen and shale gas volumes held in other product categories. Bitumen volumes have been separated from the heavy oil designation due to increased materiality to the corporate portfolio. Shale gas Product Type Transfers relate to Montney gas royalty interest volumes previously designated as Conventional Natural Gas.
(3) Columns may not add due to rounding.

Technical revisions to NGL volumes are a result of increased natural gas production processed through deep cut facilities since mid-2015. These operational changes offset technical revisions on natural gas volumes stemming from increased shrinkage losses. Remaining technical revisions were primarily related to changes to production forecasts resulting from improved production performance.

## 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 who is an independent qualified reserves evaluator.

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

## Oil and Natural Gas Properties and Wells

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

| | Natural Gas(1) | | Oil(1) | |
|---|---|---|---|---|
| **Area** | **Producing** | **Non-Producing(2)** | **Producing** | **Non-Producing(2)** |
| Alberta | 19,889 | - | 4,918 | - |
| Saskatchewan | 6,903 | - | 4,112 | - |
| British Columbia | 215 | - | 15 | - |
| Manitoba | 1 | - | 92 | - |

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

## Properties with No Attributed Reserves

The following table summarizes the undeveloped land holdings of the Company with no attributed reserves as at December 31, 2016 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(3)** | **Gross Acres** | **Gross Acres expiring within one year** | **Gross Acres** | **Net Acres** | **Net Acres expiring within one year** |
| Alberta | 3,488 | 37 | 1,433 | 78 | 190 | 190 | 114 |
| Saskatchewan | 989 | 87 | 509 | 44 | 1 | 1 | - |
| British Columbia | - | - | 456 | 25 | - | - | - |
| Manitoba | 423 | - | - | - | - | - | - |
| Other | - | - | 113 | - | - | - | - |
| **Total** | **4,900** | **124** | **2,511** | **147** | **190** | **190** | **114** |

** Numbers may not add due to rounding.-*

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 certified title to Fee Lands and GRT Lands under superior trust agreements are held in perpetuity. The number of uncertified titles and inferior trust agreements held by the Company are de minimus. As such, there is no meaningful amount of gross acres for which the Company's interests will expire during 2017.
(4) Some of this acreage may qualify to be continued by the working interest owners pursuant to other operations on the lands or offsetting lands as allowed by the regulations. Additionally, although the Company does not directly conduct operations on these lands, it makes every possible effort to have third parties actively develop the lands prior to lease expiries and therefore anticipates only a small percentage of this acreage to expire during this period.

## Tax Horizon

The Company is presently cash taxable. The statutory corporate income tax rate applicable to the Company in 2016 was approximately 27%. 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. At December 31, 2016, the Company had $1.5 billion of tax pools which can be used to offset future taxable income.

## Costs Incurred

| **Expenditure** | **Year Ended December 31, 2016 ($000s)** |
|---|---|
| Property Acquisition Costs: | |
| Proved Properties | 65,703 |
| Unproved Properties | 79,048 |
| Corporate Capital[(1)] | - |
| Total[(2)] | 144,751 |

Notes:
(1) Corporate Capital consists of office space leasehold improvements, including furniture and fixtures.
(2) Of Total Property Acquisition Costs, $48,374 relates to a corporate acquisition completed during 2016, of which $20,584 is attributable to Proved Properties and $27,790 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, 2017, in the estimates of gross and net proved and gross and net probable reserves disclosed above under the heading "*Reserves and Other Oil and Gas Information — Disclosure of Reserves Data*".

| | **Light and Medium Crude Oil** | | **Heavy Crude Oil** | | **Tight Oil** | | **Bitumen** | |
|---|---|---|---|---|---|---|---|---|
| **Reserves Category** | **Gross (1)(3)** | **Net (2)(3)** | **Gross (1)(3)** | **Net (2)(3)** | **Gross (1)(3)** | **Net (2)(3)** | **Gross(1)(3)** | **Net (2)(3)** |
| Proved | | | | | | | | |
| Developed Producing | - | 4,718 | - | 804 | - | 435 | - | 171 |
| Developed Non-Producing | - | 333 | - | 13 | - | - | - | - |
| Undeveloped | - | - | - | - | - | - | - | - |
| Total Proved | - | 5,051 | - | 817 | - | 435 | - | 171 |
| Probable | - | 227 | - | 21 | - | 31 | - | 7 |
| Total Proved Plus Probable | - | 5,278 | - | 837 | - | 466 | - | 179 |

| | Natural Gas | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Conventional | | Shale Gas | | Coal Bed Methane | | NGL | |
| Reserves Category | Gross (1)(3) | Net (2)(3) | Gross (1)(3) | Net (2)(3) | Gross (1)(3) | Net (2)(3) | Gross (1)(3) | Net (2)(3) |
| | *(Mcf/d)* | | *(Mcf/d)* | | *(Mcf/d)* | | *(bbl/d)* | |
| Proved | | | | | | | | |
| Developed Producing | - | 37,391 | - | 3,442 | - | 13,280 | - | 1,613 |
| Developed Non-Producing | - | 1,550 | - | 298 | - | - | - | 69 |
| Undeveloped | - | - | - | - | - | - | - | - |
| Total Proved | - | 38,941 | - | 3,740 | - | 13,280 | - | 1,681 |
| Probable | - | 1,500 | - | 84 | - | 223 | - | 59 |
| Total Proved Plus Probable | - | 40,441 | - | 3,824 | - | 13,503 | - | 1,740 |

| | Oil Equivalent | |
|---|---|---|
| Reserves Category | Gross (1)(3) | Net (2)(3) |
| | *(boe/d)* | |
| Proved | | |
| Developed Producing | - | 16,760 |
| Developed Non-Producing | - | 723 |
| Undeveloped | - | - |
| Total Proved | - | 17,483 |
| Probable | - | 646 |
| Total Proved Plus Probable | - | 18,128 |

Notes:
(1) Gross production represents the Company's interest in production before deduction of royalties and without including any royalty interests.
(2) Net production represents the Company's interest in production after deduction of royalty obligations plus the Company's royalty interests in production.
(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.

## Production History

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

| | Annual | 2016 | | | |
|---|---|---|---|---|---|
| | 2016 | Q4 | Q3 | Q2 | Q1 |
| **Average daily production**[1] | | | | | |
| Conventional Natural Gas *(MMcfpd)* | 74.7 | 78.2 | 74.8 | 75.3 | 70.7 |
| Light Crude Oil and Medium Crude Oil (combined) (*bbl/d*) | 8,455 | 8,583 | 8,278 | 8,213 | 8,748 |
| NGL *(bbl/d)* | 2,403 | 2,362 | 2,305 | 2,395 | 2,550 |
| Total *(boe/d)* | 23,308 | 23,978 | 23,050 | 23,158 | 23,081 |
| **Average price realized**[2] | | | | | |
| Conventional Natural Gas *($/Mcf)* | 1.65 | 2.27 | 1.84 | 0.67 | 1.80 |
| Light Crude Oil and Medium Crude Oil (combined) (*$/bbl*) | 44.22 | 52.09 | 45.79 | 45.01 | 34.16 |
| NGL *($/bbl)* | 22.01 | 24.14 | 22.21 | 22.79 | 19.09 |
| Total *($/boe)* | 23.61 | 28.47 | 24.62 | 20.50 | 20.58 |
| **Production and Mineral Tax expense** | | | | | |
| Conventional Natural Gas *($/Mcf)* | 0.04 | 0.10 | 0.01 | 0.04 | 0.03 |
| Light Crude Oil and Medium Crude Oil (combined) (*$/bbl*) | 1.46 | 2.15 | 1.62 | 0.87 | 1.19 |
| NGL *($/bbl)* | - | - | - | - | - |
| Total *($/boe)* | 0.67 | 1.09 | 0.61 | 0.48 | 0.52 |
| **Operating expense**[3] | | | | | |
| Conventional Natural Gas *($/Mcf)* | 0.70 | 0.78 | 0.66 | 0.54 | 0.82 |
| Light Crude Oil and Medium Crude Oil (combined) (*$/bbl*) | 4.21 | 4.67 | 3.97 | 3.21 | 4.92 |
| NGL *($/bbl)* | - | - | - | - | - |
| Total *($/boe)* | 3.77 | 4.22 | 3.58 | 2.89 | 4.38 |
| **Netback received**[4] | | | | | |
| Conventional Natural Gas *($/Mcf)* | 0.91 | 1.40 | 1.17 | 0.10 | 0.95 |
| Light Crude Oil and Medium Crude Oil (combined) (*$/bbl*) | 38.55 | 45.27 | 40.20 | 40.92 | 28.05 |
| NGL *($/bbl)* | 22.01 | 24.14 | 22.21 | 22.79 | 19.09 |
| Total *($/boe)* | 19.17 | 23.16 | 20.43 | 17.18 | 15.66 |

Notes:
(1) Represents net production.
(2) Excludes coal, sulphur 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 (production and mineral tax expense) and operating expense from revenues.

## Description of Properties

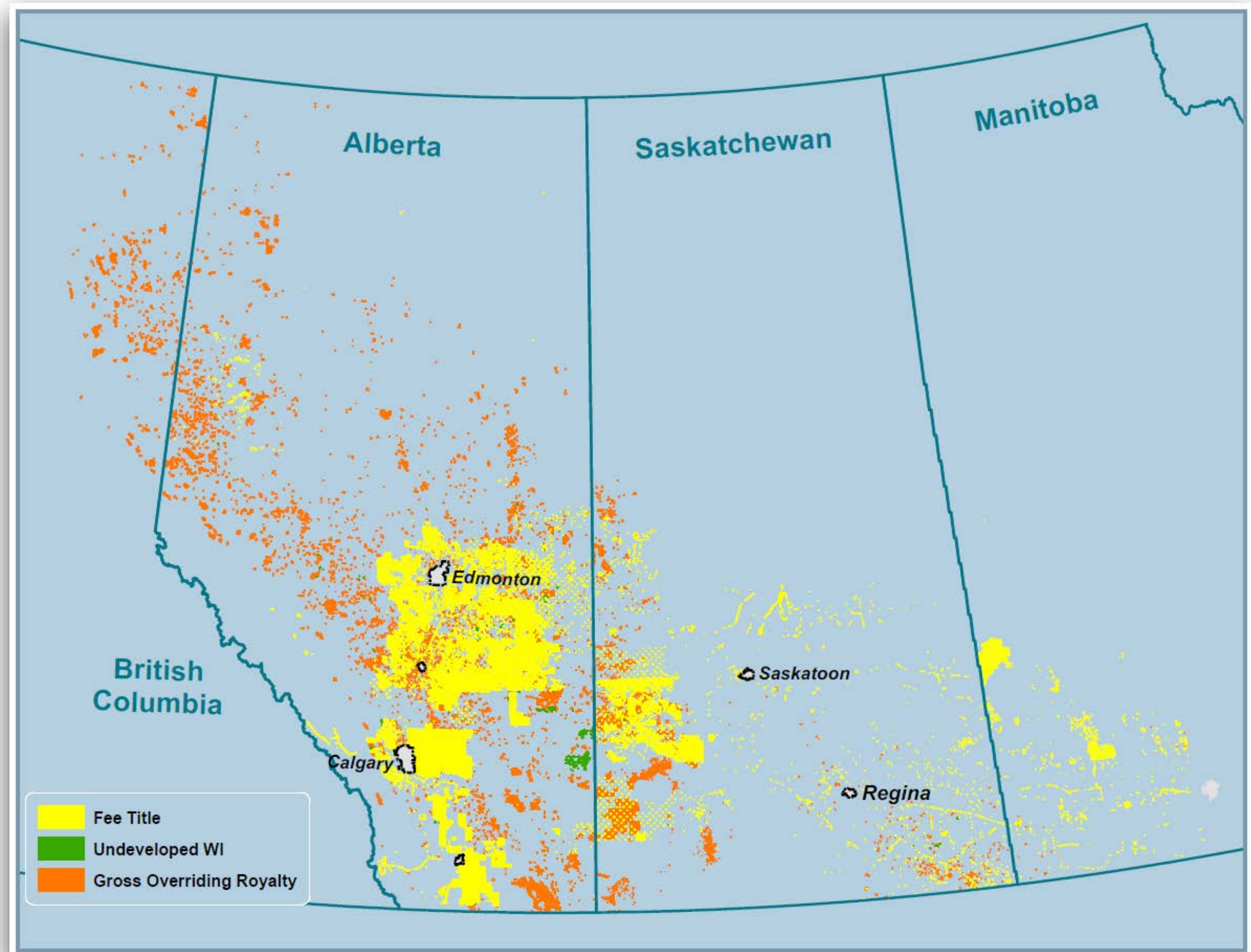
The assets of PrairieSky are comprised of: (i) the Fee Lands, encompassing approximately 7.8 million acres; (ii) the Lessor Interests; (iii) the GORR Interests, encompassing approximately 6.3 million acres of the GORR Lands; (iv) the GRT Interests, encompassing approximately 0.2 million acres of the GRT Lands; (v) approximately 0.2 million acres of Crown Interest Lands; (vi) the Seismic Licence to certain Encana proprietary seismic data and seismic data acquired pursuant to multiple acquisitions, together encompassing approximately 43,000 kilometers of 2D seismic and approximately 13,000 square kilometers of 3D seismic; and (vii) certain other related assets.

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

Approximately 20,092 leases are currently active on the Fee Lands and over 356 lessees are engaged in exploring for and producing petroleum and natural gas on the Fee Lands.

*Map of PrairieSky Fee Lands, GORR Interest and Other Interests*

Below is a map of the Royalty Properties indicating those lands which are Fee Lands, GORR Interests (including GRT Interests) and Crown Interest Lands. The following map includes lands attributable to the Pengrowth GORR Acquisition. Notwithstanding such acquisition was completed and effective subsequent to December 31, 2016.




*Lands*

The Company has one of the largest independently-owned portfolios of fee simple mineral title in Canada with approximately 8.9 million acres of Fee Lands, of which approximately 7.8 million acres are comprised of petroleum and/or natural gas rights, without the inclusion of coal rights and 1.1 million acres including coal only rights. For the period ended December 31, 2016, royalty revenue from the Fee Lands accounted for approximately 79% of the total royalty revenue of PrairieSky.

The Fee Lands include a geologically diverse portfolio of properties that span the stratigraphic column from surface to basement. There is potential for the same section of land to be leased and re-leased on the basis of geological grouping, therefore allowing multiple lessees the right to drill and explore for, and ultimately produce from, different formations depending on the particulars of their leasing arrangement.

Geological groups that form part of the Fee Lands include: (i) Surface to Top Colorado, focusing on shallow gas development; (ii) the Colorado Group, which includes the Cardium Formation and the Viking Formation in both Alberta and Saskatchewan; (iii) the Mannville Group, which includes the Detrital/Basal Quartz/Ellerslie/Ostracod, as well as the Glauconitic Formation and Upper Mannville Fahler/Wilrich/Notikewin; (iv) the Jurassic to Base Mississippian, which includes the Rock Creek, Nordegg, Rundle Group, Banff, Midale and Bakken Formations; and (v) the Devonian, which includes the Nisku and the Duvernay Formations.

### *GORR Lands*

The Company holds GORR Interests in approximately 6.3 million acres of GORR Lands. The substantial majority of the GORR Lands were acquired in connection with the Range Royalty Acquisition and the CNRL Royalty Acquisition. Most recent drilling activities on the GORR Lands were predominantly focused on the Viking Formation in southwestern Saskatchewan, the Wilrich and Duvernay Formations at Edson, the Lloydminister, Cummings and Rex Formations at Cold Lake, the Duvernay Formation at Willesden Green, the Montney/Doig, Cardium, Spirit River and Dunvegan in the Deep Basin and the Montney/Doig in northeast British Columbia.

### *GRT Lands*

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

### *Crown Interest Lands*

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

### Certain Other Mines and Mineral Rights

Coal rights, precious stone and other mines and mineral rights, 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 $25 million extendible operating credit facility (the *Credit Facility*). The Credit Facility does not have a borrowing base restriction and has a two year term, extendible annually for up to three years, subject to certain requirements. Outstanding amounts on the Credit Facility bear interest at the lender's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees. The Credit Facility requires the Company to comply with the following financial covenants at the end of each fiscal quarter: adjusted consolidated senior debt to adjusted consolidated earnings before interest, taxes, depreciation, depletion and amortization ("EBITDA") ratio must not exceed 3.0:1, adjusted consolidated total debt to adjusted consolidated EBITDA ratio must not exceed 4.0:1 and adjusted consolidated total debt to adjusted consolidated total capitalization ratio must not exceed 50%. EBITDA does not have any standardized meaning as prescribed by international financial reporting standards and may not be comparable to similarly defined measures presented by other entities. As at December 31, 2016, the Company had $25 million of available capacity under the Credit Facility 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 including the federal government and the provincial governments of Alberta, British Columbia, Saskatchewan and Manitoba, 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 governments may enact in the future. The following conditions 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, regional markets and transportation issues also influence prices. 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 underwent a consultation process to update the current regulations governing the issuance of export licences. The updating process was necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (Canada) (the *Prosperity Act*), which received Royal Assent on June 29, 2012. The *Regulations Amending the National Energy Board Act* Part IV (Oil and Gas) Regulations came into effect on July 31, 2015 and provides the requirements for obtaining long term licenses.

*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 sales 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 fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the federal government. 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 federal government. 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. Natural gas export contracts of a longer duration (to a maximum of 40 years) or that deal with larger quantities of natural gas require an exporter to obtain an export 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. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and natural gas industry is uncertain.

## 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 exploring for, developing and producing petroleum resources. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the fee simple mineral title owner and the lessee (as is the case with the Fee Lands that the Company owns and leases to third parties) and production from such lands is further subject to certain provincial taxes (including Freehold Mineral Tax). Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of 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 affect the profitability of the exploration, development and production of petroleum and natural gas related to its Lessor Interests or GORR Interests in 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.

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

### *Royalties*

### *Alberta*

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

Royalties, for wells drilled prior to January 1, 2017 are paid pursuant to "The New Royalty Framework" (implemented by the Mines and Minerals (New Royalty Framework) Amendment Act, 2008) and the "Alberta Royalty Framework" until January 1, 2027. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%.

In Alberta, the Crown owns 81% of the province's mineral rights. The remaining 19% are "freehold" mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies. Provincial government royalty rates apply to Crown-owned mineral rights. On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the *MRF*). The MRF formally took effect on January 1, 2017 for wells drilled after this date. Wells drilled prior to January 1, 2017 will continue to be governed by the previous "Alberta Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008)* (the *Previous Royalty Framework*) for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) Pre-Payout, (ii) Mid-Life, and (iii) Mature. During the Pre-Payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the Drilling and Completion Cost Allowance (determined by a formula that approximates drilling and completion costs for wells based on depth, length and historical costs). The new royalty rate for Pre-Payout under the MRF will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the Mid-Life phase will apply a higher royalty rate than the Pre-Payout phase. While the metrics for calculating the Mid-Life phase royalty have yet to be released, the rate will be determined based on commodity prices and are intended, on average, to yield the same internal rate of return as under the previous Alberta Royalty Framework. In the Mature phase, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, the equivalent of 194m$^3$ (40 barrels of oil equivalent per day or 345,500m$^3$ of gas per month), the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well. Details of the MRF, including the applicable royalty rates and formulas, were released on April 21, 2016.

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

Oil sands projects are also subject to Alberta's royalty regime. The MRF does not change the oil sands royalty framework; however, the Government of Alberta plans to increase transparency in the method and figures by which the royalties are calculated will be released to the public. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma. Rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher.

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

Royalties for wells drilled prior to January 1, 2017 are paid pursuant to the Previous Royalty Framework until January 1, 2027. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the previous Alberta Royalty Framework is 40% and the minimum royalty rate is 5%. Royalty rates for natural gas under the previous Alberta Royalty Framework depend on the price of each of the components of the gas stream, the productivity of the well, the acid gas factor and the depth of the producing zone. These factors are employed on a sliding scale formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36% and a minimum royalty set at 5%.

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

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. 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*). These initiatives apply to wells drilled before January 1, 2017 for a 10 year period until January 1, 2027. Specifically:

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

### *British Columbia*

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" which is produced from a pool discovered between October 31, 1975, and June 1, 1998, and "third-tier oil" which is produced from a pool discovered after June 1, 1998, or through an enhanced oil recovery (*EOR*) scheme. The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low-productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well, and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20% of sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the applicable freehold production tax is based on the volume of monthly production and is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold natural gas liquids is a flat rate of 12.25%.

As of January 1, 2017, all liquid natural gas (*LNG*) facilities are subject to a 3.5% income tax. This income tax is scheduled to increase to 5% in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5% will apply to the taxpayer's net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5% is payable. To encourage investment, the Government of British Columbia will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

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

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met, is intended to reflect the higher drilling and completion costs. Effective April 1, 2014, there are two tiers to the Deep Well Royalty Credit Program, "tier one" and "tier two". The pre-existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than or equal to 1,900 metres if spud after March 31, 2014. Currently all wells that qualify for the tier one royalty credits are subject to a minimum royalty of 6% while wells that qualify for the tier two royalty credits are subject to a minimum royalty of 3%. These minimum royalty amounts apply when the net royalty payable would otherwise be zero for a production month;

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

- *Deep Discovery Royalty Credit Program* providing the lesser of a three year royalty holiday or 283,000,000 $m^3$ of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 $m^3$ as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

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

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 $m^3$ per metre of depth for exploratory wildcat wells and less than 11 $m^3$ per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 $m^3$. Horizontal wells that are spud on or after April 1, 2014, are not eligible for the Ultra-Marginal Royalty Reduction Program due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974, may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 $m^3$ of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

### *Saskatchewan*

In Saskatchewan, the Crown owns approximately 70% of the oil and natural gas rights. For Crown lands, taxes (*Resource Surcharge*) and royalties are applicable to revenue generated by corporations focused on oil and gas operations.

A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act*. For resource corporations, the Resource Surcharge rate is 3% of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. The Resource Surcharge applies to resource trusts in addition to resource corporations.

The amount payable as Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The 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 m3 for "old oil", "new oil" and "third tier oil", and 250 m3 per month for "fourth tier oil". Where average wellhead prices are below the established base prices of $100 per m3 for third and fourth tier oil and $50 per m3 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 at least 3,500 m3 of gas for every m3 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. NGL and by-products recovered at gas processing plants are not subject to a royalty. NGL, 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 250,000 m3/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per GJ for third and fourth tier gas and $0.95 per GJ 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 m3 for deep development vertical oil wells, 4,000 m3 for non-deep exploratory vertical oil wells and

16,000 m3 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 m3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002,* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 m3 for non-deep horizontal oil wells and 16,000 m3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010,* and before April 1, 2013, providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m3 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 with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013, to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting 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. The new standards apply to existing licensed wells and facilities on July 1, 2015.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses and applications in the oil and gas sector by eliminating eleven (11) different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company's production and number of wells. Effective October 27, 2016, the Saskatchewan Ministry of the Economy streamlined a further 20 different service fees, and implemented a Crown minerals Electronic Registry for oil and natural gas tenure in Saskatchewan that will provide for certainty of tenure comparable to Alberta and reduce the administrative burden.

### *Manitoba*

In Manitoba, the Crown owns approximately 20% of the oil and natural gas rights in the province, with the remainder being freehold lands. The royalty amount payable on oil produced from Crown lands depends on the classification of the oil produced as "old oil" (produced from a well drilled prior to April 1, 1974, that does not qualify as new oil or third tier oil), "new oil" (oil that is not third tier oil and is produced from a well drilled on or after April 1, 1974, and prior to April 1, 1999, from an abandoned well re-entered during that period, from an old oil well as a result of an enhanced recovery project implemented during that period, or from a horizontal well), "third tier oil" (oil produced from a vertical well drilled after April 1, 1999, an abandoned well re-entered after that date, an inactive vertical well activated after that date, a marginal well that has undergone a major workover, or from an old oil well or a new oil well as a result of an enhanced recovery project implemented after that date), or "holiday oil" (oil that is exempt from any royalty or tax payable). Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations.

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

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

The Government of Manitoba maintains a Drilling Incentive Program (the *Program*) with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no Crown royalties or freehold production taxes are payable until the holiday oil volume has been produced. Holiday oil volumes must be produced within 10 years of the finished drilling date or the completion date of a major workover.

Wells that are drilled or receiving a marginal well major workover incentive after December 31, 2013, and prior to January 1, 2019, must pay a minimum royalty of 3% on Crown production or a minimum tax of 1% on freehold production. Wells receiving the *Pressure Maintenance Project Incentive* (outlined below) are not subject to the minimum royalty or minimum tax.

Wells that are drilled for injection, or converted to injection wells, in an approved enhanced recovery project, earn a one year holiday for portions of the project area.

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

- *Vertical Well Incentive* provides licensees of a vertical development or exploratory well drilled after December 31, 2013, and prior to January 1, 2019, with a holiday oil volume (a *HOV*) of 500 m$^3$. To qualify, the well must be less than 1.6 kilometres from the nearest well cased for production from the same or deeper zone;

- *Exploration and Deep Well Incentive* provides a HOV for exploratory or deep oil development wells drilled after December 31, 2013, and prior to January 1, 2019, as follows:
    - Non-deep exploratory wells drilled more than 1.6 kilometres from the nearest well cased for production from the same or deeper zone earn a HOV of 4,000 $m^3$;
    - Deep exploratory wells drilled below the Birdbear formation earn a HOV of 8,000 $m^3$; and
    - Deep development wells completed for production in the Birdbear formation or deeper earn a HOV of 8,000 $m^3$;
- *Horizontal Well Incentive* provides a HOV of 8,000 $m^3$ for any horizontal well drilled after December 31, 2013, and prior to January 1, 2019, achieving an angle of at least 80 degrees for a minimum distance of 100 metres;
- *Marginal Well Major Workover Incentive* provides a HOV of 500 $m^3$ for any marginal well where a major workover is completed prior to January 1, 2019. A marginal oil well is a well or abandoned well that was not operated over the previous 12 months or that produced at an average rate of less than 3 $m^3$ per operating day;
- *Pressure Maintenance Project Incentive* provides a one-year exemption from the payment of Crown royalties or freehold production taxes for the unit tract in which an injection well is drilled or a well is converted to water injection. This exemption applies to the unit tract in which the vertical injection well is located and for a horizontal injection well to a maximum of four unit tracts within the drainage unit of the well. For a well that is converted to injection after December 31, 2013, and before January 21, 2019, and that has a remaining HOV, the exemption will be extended to 18 months; and
- *Solution Gas Conservation Incentive* provides a royalty and tax exemption on gas until December 31, 2018, for projects after December 31, 2013 that capture solution gas.

The Holiday Oil Volume Account, which allowed the movement of HOV to and from wells under specific conditions, was eliminated January 1, 2015. Previously, the holder of an existing account was able to make a one-time transfer of 2,000 $m^3$ to a well drilled between January 1, 2014, and December 31, 2014.

### *Land Tenure*

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces, with the exception of Manitoba where private ownership accounts for approximately 80% of the crude oil and natural gas rights in the southwestern portion of the province. Provincial governments 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 Encana Royalty Acquisition). The Lessor Interests consist of the rights of the Company as set forth under such leases.

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

In respect of the GORR Interests granted out of Crown leases, in addition to the varying terms and conditions set forth in provincial legislation, the Provinces of Alberta, British Columbia, Saskatchewan, and Manitoba have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. British Columbia expanded its policy of deep rights reversion for leases issued after March 29, 2007, to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of the primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and 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 and are provided with a five-year term after which shallow rights reversion will apply. Deep rights reversion occurs at continuation.

### *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. Such matters are outside of the Company's control and could negatively impact the Company.

### *Environmental Regulation*

The oil and natural gas industry is currently subject to environmental regulation pursuant to a variety of provincial and federal environmental legislation and territorial and municipal laws and regulation, all of which is subject to governmental review and revision from time-to-time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regime requires operators to obtain operating licenses and permits and sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas (*GHG*) emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

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

Pursuant to the *Prosperity Act*, the federal government amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environmental assessment regime. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction. On June 20, 2016, the federal government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. An expert panel has been convened and is expected to complete its work by March 31, 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the panel's report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the federal government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment processes. The federal government has not provided any indication on what changes, if any, will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

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

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the AER assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* (*ABOGCA*). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development (*AESRD*) in respect of the disposition and management of public lands under the Public Lands Act. On March 29, 2014, the AER assumed the energy related functions and responsibilities of AESRD in the areas of environment and water under the Environmental Protection and Enhancement Act and the Water Act, respectively.

The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

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

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the *ALUF*). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. Proclaimed in force in Alberta on October 1, 2009, the *Alberta Land Stewardship Act* (the *ALSA*) provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established under the ALSA are deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licences, registrations, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan.

Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan (*LARP*) which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 km$^2$ in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82 per cent of the province's oil sands resources and much of the Cold Lake oil sands area. LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oil sands companies' tenure has been (or will be) cancelled in conservation areas and no new oil sands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access. The next regional plan to take effect is the South Saskatchewan Regional Plan (*SSRP*) which covers approximately 83,764 km$^2$ and includes 45 per cent of the provincial population. The SSRP was approved by the Cabinet of the provincial government on July 23, 2014 and came into effect force on September 1, 2014. With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Phase 1 Consultation of the North Saskatchewan Region Plan (*NSRP*) has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The NSRP is located in central Alberta and is approximately 85,780 square kilometres in size. The Upper Peace Region Plan, Lower Peace Region Plan, Red Dear Region Plan and Upper Athabasca Region Plan have not been started.

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

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

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

### *Liability Management Rating Programs*

In Alberta, the AER administers the Licensee Liability Rating Program (the *AB LLR Program*). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOCGA establishes an orphan well fund (the *Orphan Well Fund*) to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant (*WIP*) becomes defunct or unable to meet its obligations. The Orphan Well Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Well Fund posed by unfunded licensees' liabilities and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER. The AER publishes the liability management rating for each licensee on a monthly basis.

Effective May 1, 2013, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed liabilities to deemed assets under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

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

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

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

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

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

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

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

In Saskatchewan, the Ministry of Economy administers the Licensee Liability Rating Program (the *SK LLR Program*). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan well fund (the *Oil and Gas Orphan Well Fund*) established under the SKOGCA. The Oil and Gas Orphan Well Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities. On August 19, 2016, the Ministry of the Economy released a notice to all operators that it would follow the AER's interim rules by processing all license transfer applications as non-routine until further notice.

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

### *Freehold Mineral Tax*

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*. 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 total product revenues.

Although the registered fee simple mineral title owner is responsible for paying the Freehold Mineral Tax, most lease 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.

## Climate Change Regulation

### *Federal*

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

On April 26, 2007, the federal government released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the *Action Plan*) which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the *Updated Action Plan*). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific basis, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors.

As a signatory to the *United Nations Framework Convention on Climate Change* (the *UNFCCC*) and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC), the federal government announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, the GHG emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution (*INDC*) to the UNFCCC. INDCs were communicated prior to the 2015 United Nations Climate Change Conference, held in Paris, France, which led to the Paris Agreement that came into force November 4, 2016 (the *Paris Agreement*). Among other items, the Paris Agreement constitutes the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The federal government ratified the Paris Agreement on December 12, 2016, and pursuant to the agreement, Canada's INDC became its Nationally Determined Contributions (*NDC*). As a result, the federal government replaced its INDC of a 17% reduction target established in the Copenhagen Accord with an NDC of 30% reduction below 2005 levels by 2030.

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

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

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

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the *CCEMA*) enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The accompanying regulations include the *Specified Gas Emitters Regulation*

(*SGER*), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to facilities emitting more than 100,000 tonnes of GHG emissions in 2003 or any subsequent year (*Regulated Emitters*), and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER.

On June 25, 2015, the Government of Alberta renewed the *SGER* for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. As of 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

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

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

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

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia launched its Climate Action Plan in 2008 and met its first interim emission reduction targets in 2012. In February 2008, the Government of British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of GHG emissions. The final scheduled increase took effect on July 1, 2012, wherein the Government of British Columbia froze the tax level to allow other jurisdictions time to adopt comparable carbon pricing mechanisms. In order to make the tax revenue-neutral, the Government of British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

Further, on April 3, 2008, the Government of British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the *Cap and Trade Act*), which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33% reduction in the 2007 level of GHG emissions by 2020 and an 80% reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Alberta government, the *Cap and Trade Act* establishes an absolute cap on GHG emissions.

The *Greenhouse Gas Emission Reporting Regulation*, implemented under the authority of the *Cap and Trade Act*, set out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. The reporting system for large emitters of GHGs has since been streamlined by the *Greenhouse Gas Industrial Reporting and Control Act* (the *GGIRCA*) and its associated regulations that came into force on January 1, 2016. The *GGIRCA* sets out benchmarked performance standards for different industrial facilities and sectors, provides for emissions offsets through the purchase of emission credits or emission offsetting projects, among other measures, and replaces the *Cap and Trade Act*.

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

On August 19, 2016, the Government of British Columbia unveiled its Climate Leadership Plan with a goal to reduce net annual GHG emissions by up to 25 million tonnes below current forecasts by 2050, and reaffirmed that it will achieve its 2050 target of an 80% reduction in emissions from 2007 levels. In addition to various measures across the economy that are designed to incentivize the growth of the renewable energy sector, the use of low GHG emitting technologies, and the improvement of energy efficiency, among other goals, the Government of British Columbia will soon implement a formal policy to regulate carbon capture and storage projects. Further, the Climate Leadership Plan sets out a strategy to reduce methane emissions in the upstream natural gas sector, beginning with a Legacy phase that targets a 45% reduction in fugitive and vented emissions by 2025 for facilities built before January 1, 2015, followed by a Transition phase for facilities built between 2015 and 2018 that involves a new offset protocol and a Clean Infrastructure Royalty Credit Program along with other incentives, and finally a Future phase that will implement standards going forward.

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the *MRGGA*) to regulate GHG emissions in the province. The *MRGGA* received Royal Assent on May 20, 2010 and will come into force on proclamation. The *MRGGA* establishes a framework for achieving the provincial target of a 20% reduction in GHG emissions from 2006 levels by 2020. Although the *MRGGA* and related regulations have yet to be proclaimed in force, draft versions indicate that the Government of Saskatchewan will permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to the federal climate change initiatives. It remains unclear whether the scheme implemented by the *MRGGA* will be based on emissions intensity or an absolute cap on emissions.

The Government of Manitoba commenced public consultations with respect to the development of a cap and trade system to reduce GHG emissions in 2010. The enactment of *The Climate Change and Emissions Reductions Act* (Manitoba) set emission reduction targets as of December 31, 2012 at 6% below 1990 emissions and details the commitment of the Government of Manitoba to various initiatives in an effort to reduce GHG emissions. On December 3, 2015, the Government of Manitoba announced Manitoba's Climate Change and Green Energy Action Plan to address climate change and create green jobs. One component of this plan involves cutting GHG emissions by one-third of its 2005 levels by 2030, in part by implementing a cap and trade program for large emitters. Following this announcement, on December 7, 2015, the Government of Manitoba announced that it has signed a memorandum of understanding with both Ontario and Quebec formalizing the intent of all three provinces to link their respective cap-and-trade systems. However, legislation has not yet been enacted to implement the initiatives outlined in Manitoba's Climate Change and Green Energy Action Plan or the memorandum of understanding.

## RISK FACTORS

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

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

### *Dependence on Lessees and/or Operators*

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

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

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

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

*Third Party Exploration, Development and Production Risks*

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 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 ensure a profit on the investment or recovery of drilling, completion (including hydraulic fracturing) 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 wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect a third party's production from the Royalty Properties, which may reduce the Company's revenue.

*Additional Capital and Funding Requirements at Onion Lake and Lindbergh*

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

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

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

*Third Party Credit Risk*

The Company 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. See "*Risk Factors – Dependence on Lessees and/or Operations*" and "*Risk Factors – Weakness in the Oil and Gas Industry*".

### *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 and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of 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. Notwithstanding recent OPEC discussions and cooperation on production freezes, oil prices are expected to remain volatile and may decline further in the near future as a result of global excess supply due to increased growth of shale production in the United States, the decline of global demand for exported crude commodities, and the failure of major producers (including OPEC and non-OPEC countries) to implement meaningful and/or lasting production cuts.

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 production activities. Any substantial and extended decline in or continued low crude oil and natural gas prices would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows and may have a material adverse effect on the Company's business and financial condition.

Crude oil and natural gas prices have varied greatly over the last two years 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 oversupply, the current state of the world economies, OPEC actions, political uncertainties 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.

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

### *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 in certain circumstances, by 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 could result in an inability to realize the full economic potential of the Royalty Properties. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and natural gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export petroleum and natural gas. Unexpected shutdowns or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect third parties' production and operations which may have a material adverse effect on the Company's business and financial condition. As a result, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, including remedial work on certain pipeline sections, as well as any delays or uncertainty in constructing new infrastructure systems and facilities, could harm the ability of third parties to develop and produce from the Royalty Properties and, in turn, the Company's business and financial condition. In addition, the federal government has signalled that it plans to review the National Energy Board approval process for large federally regulated projects. This may cause the timeframe for project approvals to increase for current and future applications.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the federal government passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail, imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on D07-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure that they are compliant with Protective Direction No. 38.

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.

### *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) as well as skilled personnel trained to use such equipment. Demand for such limited equipment, skilled personnel 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.

*Weakness in the Oil and Gas Industry*

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

*Political Uncertainty*

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

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

*Geopolitical Risks*

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

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.

### *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 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.

### *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. In addition, extreme cold weather, heavy snowfall and heavy rain may restrict access to the Royalty Properties and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and also to volatility in commodity prices as the demand for natural gas rises during cold winter months and hot summer months.

### *Regulatory*

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 production and mineral taxes, may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for 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. In addition, the Company may have to comply with the requirements of certain federal legislation such as the *Competition Act (Canada)* and the *Investment Canada Act* which may materially adversely affect its business and financial condition and the market value of the Common Shares or our assets, particularly when undertaking or attempting to undertake an acquisition or disposition activity.

### *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.

### *Liability Management Ratings Programs*

Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its obligation. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes to the required ratio of third party operators deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the security that must be posted by such third parties, which could impact the availability of capital to be spent by them which could in turn materially adversely affect the Company's business and financial condition. See "*Industry Conditions – Liability Management Ratings Programs*".

The recent Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re)* 2016 ABQB 278, found an operational conflict between the BIA and the AER's abandonment and reclamation powers when the licensee is insolvent. The AER appealed this decision and issued interim rules to administer the liability management program and until the Alberta Government can develop new regulatory measures to adequately address environmental liabilities. The decision from this appeal has not been released. There remains a great deal of uncertainty as to what new regulatory measures will be developed or what the impact of the court decision will have on other provinces. See "*Industry Conditions - Liability Management Rating Programs*".

### *Royalty Regimes*

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the third party lessees of Crown lands. An increase in royalties would reduce the Company's earnings and could make future capital investments by third parties on the Crown lands less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See "*Industry Conditions - Royalties and Incentives*".

### *Climate Change*

Operations and activities associated with the Royalty Properties emit greenhouse gases (*GHG*) 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 federal government announced in 2010 that it would seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets were not binding; however, as a result of the United Nations Framework Convention of Climate Change adopting the Paris Agreement on December 12, 2015 which Canada ratified on October 3, 2016, the federal government implemented new GHG emission reduction targets of a 30% reduction from 2005 levels by 2030. In addition, the federal government announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. On January 1, 2017, the CLA came into effect in the province of Alberta, introducing a carbon tax on almost all sources of GHG emissions at a rate of $20 per tonne, increasing to $30 per tonne in January 2018. 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.

*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.

*Other Title Risks, including those applicable to Gross Overriding Royalties*

The majority of our GORR Interests attach to licenses and leases and working interests in licenses and leases. If the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire thereby terminating our GORR Interest. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of a license or lease or the working interest relating to a license or lease may have a material adverse effect on our results of operations and business. In addition title to the properties can become subject to dispute and defeat our claim to title over certain of our properties. Furthermore, there may be legislative changes which affect title to the leases and licenses to which GORR Interests attach that, if successful or made into law, could impair our royalty interests and result in a reduction of the revenue received by us.

*Litigation and Aboriginal Claims*

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

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

### *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 may realize less on disposition than what the market may expect for such disposition or their carrying value on the financial statements of the Company.

### *Management of Growth and Integration*

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

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

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar 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, 2016, with a preparation date of February 10, 2017, and, except as may be specifically stated or required by applicable securities laws, has not been updated since that date.

### *Market Price of Common Shares*

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

### *Negative Impact of Additional Sales or Issuances of Common Shares*

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

### *Capital and Additional Funding Requirements*

The Company's cash flow from the Royalty Properties may not be sufficient to fund its ongoing activities at all times, and from time to time the Company may require additional financing, which may include financing for the acquisition of additional 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; commodity prices; the Company's credit rating (if applicable); interest rates; tax burden due to current and future tax laws; and investor appetite for investments in the energy industry and the Company's securities in particular.

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

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

### *Cash Dividend Payments are not Guaranteed*

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

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

### *Foreign Exchange Risk on Dividends*

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

### *Additional Taxation Applicable to Dividends Paid to Non-Residents*

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

### *Variations in Foreign Exchange Rates and Interest Rates*

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

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. Such hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

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

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

### *Income Taxes*

Income tax laws relating to the oil and natural gas industry such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Company.

Furthermore, tax authorities having jurisdiction over the Company may disagree with how the Company calculates its income for tax purposes or could change administrative practices to the Company's detriment.

The Company files all required income tax returns in order to be in full compliance with the provisions of the Tax Act and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Company, such reassessment may have an impact on current and deferred taxes payable.

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

### *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 personnel 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.

### *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.

*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.

*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 generally 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.

*Information Technology Systems and Cyber-Security*

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

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

*Access to Our Offices and Properties*

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

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

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

### *Forward-Looking Information May Prove Inaccurate*

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

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

## 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 27, 2017, 237,115,530 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. During 2016, the Company purchased, for cancellation, 960,000 Common Shares under its previously filed normal course issuer bid.

**Toronto Stock Exchange**
**Common Shares Trading Range**

| | High ($/Common Share) | Low ($/Common Share) | Volume Traded |
|---|---|---|---|
| **2016** | | | |
| January | 22.62 | 17.15 | 26,623,901 |
| February | 22.49 | 18.03 | 25,776,912 |
| March | 26.52 | 21.75 | 27,285,361 |
| April | 26.99 | 22.59 | 13,652,387 |
| May | 26.41 | 23.53 | 8,417,456 |
| June | 26.38 | 22.91 | 16,636,367 |
| July | 26.30 | 24.15 | 8,555,148 |
| August | 27.69 | 24.85 | 9,963,242 |
| September | 27.49 | 25.50 | 10,359,402 |
| October | 30.79 | 26.74 | 9,789,261 |
| November | 33.20 | 27.41 | 15,330,488 |
| December | 34.32 | 31.36 | 12,140,711 |
| **2017** | | | |
| January | 33.36 | 29.84 | 10,050,757 |
| February (1-24) | 30.94 | 28.52 | 10,410,162 |

## DIVIDENDS

The Board has established a dividend policy pursuant to which the Company pays a monthly dividend of $0.06 per Common Share per month or $0.72 per Common Share on an annualized basis. On February 27, 2017, PrairieSky announced that the Board had approved and increased the dividend to $0.0625 per Common Share per month or $0.75 per Common Share on an annualized basis, effective for the March 31, 2017 dividend record date which is expected to be paid on or about April 17, 2017. The Board reviews and determines the dividend rate annually after considering expected commodity prices, foreign exchange rates, economic conditions, production volumes, taxes payable, and PrairieSky's capacity to fund operating and investing opportunities. The dividend rate is established with the intent of absorbing short-term market volatility over several months. It also recognizes the intention of maintaining a strong financial position to take advantage of business development opportunities and withstand periods of commodity price volatility.

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

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

| Month of Dividend Payment Date | |
|---|---|
| **2016** | |
| January | $0.10833 |
| February | $0.10833 |
| March | $0.06000 |
| April | $0.06000 |
| May | $0.06000 |
| June | $0.06000 |
| July | $0.06000 |
| August | $0.06000 |
| September | $0.06000 |
| October | $0.06000 |
| November | $0.06000 |
| December | $0.06000 |
| **2017** | |
| January | $0.06000 |
| February | $0.06000 |

**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 27, 2017, 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)<br>Calgary, Alberta, Canada | Corporate Director | April 11, 2014 |
| **Margaret McKenzie**(3)(4)<br>Calgary, Alberta, Canada | Corporate Director | December 19, 2014 |
| **Andrew M. Phillips**<br>Calgary, Alberta, Canada | President & Chief Executive Officer of the Company | April 11, 2014 |
| **Sheldon B. Steeves**(2)(3)(4)<br>Calgary, Alberta, Canada | Corporate Director | April 11, 2014 |
| **Grant A. Zawalsky**(2)(4)<br>Calgary, Alberta, Canada | Managing Partner, Burnet, Duckworth & Palmer LLP | December 19, 2014 |

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

### Executive Officers of PrairieSky

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

| Name, Province and Country of Residence | Principal Occupation | Date of Appointment as an Officer |
|---|---|---|
| **Andrew M. Phillips**<br>Calgary, Alberta, Canada | President & Chief Executive Officer of the Company | April 11, 2014 |
| **Cameron M. Proctor**<br>Calgary, Alberta, Canada | Chief Operating Officer of the Company | April 11, 2014 |
| **Pamela Kazeil**<br>Calgary, Alberta, Canada | Vice-President, Finance & Chief Financial Officer of the Company | June 1, 2015 |
| **Michelle Radomski**<br>Calgary, Alberta, Canada | Vice President, Land of the Company | December 19, 2014 |

As at February 27, 2017, the directors and executive officers of PrairieSky, as a group, beneficially own or control, directly or indirectly, 2.4 million Common Shares or 1% of the issued and outstanding Common Shares.

### Directors and Executive Officers Biographical Information

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

### James M. Estey

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

### Margaret McKenzie

Ms. McKenzie was formerly the Vice President, Finance and Chief Financial Officer of Range GP and prior thereto was Vice President, Finance and Chief Financial Officer of Profico Energy Management Ltd. (a private oil and natural gas company). Ms. McKenzie holds a Bachelor of Commerce degree (with distinction) from the University of Saskatchewan and has been a member of the 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 Bonavista Energy Corporation, a TSX-listed oil and natural gas company, Encana Corporation, a TSX and NYSE listed oil and natural gas company, Inter Pipeline Ltd., a TSX listed petroleum transportation, storage and natural gas liquids extraction company, and two private energy companies.

### 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., a private oil and natural gas company founded by Mr. Phillips in 2010 with producing properties and royalty interests in southwest Saskatchewan and Alberta. Home Quarter was successfully divested to a public oil and natural gas company in 2014. Prior thereto, Mr. Phillips was the Vice President, Exploration at Evolve Exploration Ltd., a private junior oil and natural gas company with assets in western Canada, and an exploration geologist at Profico Energy Management Ltd. and at Renaissance Energy Ltd., both of which were Canadian oil and natural gas exploration companies. Mr. Phillips holds a Bachelor of Science, Geology degree from the University of Calgary and is a member of the Association of Professional Engineers and Geoscientists of Alberta and the Canadian Society of Petroleum Geologists.

### Sheldon B. Steeves

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

### Grant A. Zawalsky

Mr. Zawalsky is the Managing Partner of Burnet, Duckworth & Palmer LLP (Barristers and Solicitors) where he has been a partner since 1994. Mr. Zawalsky holds a B.Comm and LL.B. from the University of Alberta and is a member of the Law Society of Alberta. Mr. Zawalsky is an experienced director and currently sits on the board of directors of a number of private and public companies, including Whitecap Resources Inc., NuVista Energy Ltd. and Zargon Oil & Gas Ltd.

### Cameron M. Proctor

Mr. Proctor is the Chief Operating Officer of the Company, as well as the Corporate Secretary of the Company, and has experience in the oil and natural gas industry managing several business units including legal, 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.

### Pamela Kazeil

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

### Michelle Radomski

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

### Corporate Cease Trade Orders or Bankruptcies

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

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

### Personal Bankruptcies

None of the directors or executive officers of PrairieSky has nor any shareholder holding sufficient number of securities of the Company to affect materially the control of the Company, within the past 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 has adopted specific policies and procedures for the engagement of non-audit services. The policies and procedures allow for the pre-approval of certain services. For additional services, the audit committee pre-approves expenditures with a dollar limit for services. The Audit Committee must pre-approve any costs that exceed these limits. All audit and non-audit services are reported to the Audit Committee quarterly.

### *External Auditor Service Fees*

| | Year Ended December 31, 2015 | Year Ended December 31, 2016 |
|---|---|---|
| Audit fees[(1)] | $498,000 | $203,800 |
| Audit-related fees[(2)] | $154,000 | $- |
| Tax fees[(3)] | $110,000 | $13,939 |
| All other fees[(4)] | $ 21,500 | $- |
| Total | $783,500 | $217,739 |

Notes:
(1) Audit fees consist of aggregate fees billed for the audit of PrairieSky's annual financial statements, reviews of interim consolidated financial statements for the quarters of 2015 and 2016 fiscal years, or services that are normally provided in connection with statutory and regulatory filings or engagements.
(2) Audit-related fees consist of aggregate fees billed for assurance and related services that are reasonably related to the performance of the audit or review of PrairieSky's financial statements and are not reported as Audit Fees.
(3) Aggregate fees billed related to tax services.
(4) Aggregate fees billed for services related to an assessment of the Company's information technology environment.

## CONFLICTS OF INTEREST

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

## LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

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

## INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

## TRANSFER AGENT AND REGISTRAR

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

## MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contract 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, is the following:

- *Seismic Licence Agreement*. As part of the Encana Royalty Acquisition pursuant to the Encana 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 Encana Purchase and Sale Agreement.

## INTERESTS OF EXPERTS

### Names of Experts

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

### Interest of Experts

KPMG LLP is the auditor of the Company and is independent 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) GLJ, beneficially owned, directly or indirectly, less than 1% of our outstanding securities including the securities of our associate or affiliate entities.

In addition, none of the aforementioned persons or companies, nor any partner, director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of PrairieSky 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, 2016, 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 which relates to the Annual General Meeting of Shareholders to be held on April 25, 2017.

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

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

# Appendix A

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

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

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

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

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

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

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

| Independent Qualified Reserves Evaluator or Auditor | Effective Date of Evaluation Report | Location of Reserves (Country or Foreign Geographic Area) | Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – MM$) - | | | |
|---|---|---|---|---|---|---|
| | | | Audited | Evaluated | Reviewed | Total |
| GLJ Petroleum Consultants | December 31, 2016 | Canada | - | 1,024.4 | - | **1,024.4** |

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

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

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

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 10, 2017

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

# APPENDIX B

## Form 51-101F3

### Report of Management and Directors on Oil and Gas Disclosure

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

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

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

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

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

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

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

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

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

(f) the content and filing of this report.

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

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

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

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

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

DATED as of this 27 day of February, 2017.

# APPENDIX C

## AUDIT COMMITTEE MANDATE

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

### Composition of Committee

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

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

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

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

### Appointment of Committee Members

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

### Chair

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

**Committee Meetings**

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

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

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

**Notice of Meeting**

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

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

**Quorum**

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

**Attendance at Meetings**

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

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

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

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

**Minutes**

The Committee shall appoint a secretary who need not be a member of the Committee. The secretary shall keep minutes of the meetings of the Committee. Minutes of Committee meetings shall be sent to all Committee members and the external auditors. The full Board shall be kept informed of the Committee's activities by a report following each Committee meeting, unless each Board member who is not also a member of the Committee is in attendance at such Committee meeting.

**Specific Responsibilities**

**Review Procedures**

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

**Annual Financial Statements**

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

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

   (b) Management's Discussion and Analysis;

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

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

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

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

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

   (a) Year-end audited financial statements; and

   (b) Management's Discussion and Analysis.

**Quarterly Financial Statements**

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

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

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

**Other Financial Filings and Public Documents**

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

5. Review and discuss with management financial information, including annual and interim earnings press releases, the use of "pro forma" or non-GAAP financial information and 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 must be satisfied that adequate procedures are in place for the review of PrairieSky's disclosure of all other financial information and shall periodically assess the accuracy of those procedures.

**Internal Control Environment**

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

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

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

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

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

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

**Other Review Items**

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

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

14. Review legal and regulatory matters, including correspondence and filings with regulators and governmental agencies, which may have a material impact on the interim or annual financial

statements, related corporate compliance policies, and programs and reports received from regulators or governmental agencies, including but not limited to reporting documents filed under the *Extractive Sector Transparency Measures Act*.

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

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

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

18. Meet on a periodic basis separately with management.

**External Auditors**

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

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

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

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

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

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

22. Review and evaluate:

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

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

(c) External audit plans and results; and

(d) Any other related audit engagement matters.

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

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

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

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

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

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

**Approval of Audit and Non-Audit Services**

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

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

27. If the pre-approvals contemplated in paragraphs 24 and 25 are not obtained, approve, where appropriate and permitted, the provision of all audit and non-audit services promptly after the Committee or a member of the Committee to whom authority is delegated becomes aware of the provision of those services.

28. Delegate, if the Committee deems necessary or desirable, to subcommittees consisting of one or more members of the Committee, the authority to grant the pre-approvals and approvals described in paragraphs 24 through 26. The decision of any such subcommittee to grant pre-approval shall be presented to the full Committee at the next scheduled Committee meeting.

29. The Committee may establish policies and procedures for the pre-approvals described in paragraphs 24 and 25, so long as such policies and procedures are detailed as to the particular service, the Committee is informed of each service and such policies and procedures do not include delegation of the Committee's responsibilities under applicable Canadian federal and provincial legislation and regulations to management.

**Other Matters**

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

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

32. Conduct or authorize any review or investigation into any matters within the Committee's scope of responsibilities. The Committee shall have unrestricted access to personnel and information and any resources necessary to carry out its responsibility. The Committee shall be empowered to

retain, obtain advice or otherwise receive assistance from independent counsel, accountants, or others to assist it in the conduct of any investigation as it deems necessary and in carrying out of its duties. The Committee shall have the authority to set and pay compensation for any such advisors.

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

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

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

Effective: Amended February 27, 2017