



2016 Annual Information Form

March 2, 2017

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ADVISORIES

Cautionary Statement Regarding Forward-Looking Information and Statements

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

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

- Freehold Royalties Ltd.'s ("**Freehold**" or the "**Corporation**") strategy with respect to future acquisitions and the possibility that the Board of Directors may vary the strategy in the future;
- the performance characteristics of our oil and natural gas properties;
- the estimated future value of the Corporation's oil and natural gas reserves;
- projected oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;
- estimated abandonment and reclamation costs;
- the expected future development costs associated with development of the Corporation's reserves;
- plans for development of undeveloped reserves;
- the funding and payment of future dividends;
- the expectations for the funding of capital expenditures;
- the expectation of certain activities to be undertaken by operators in areas in which the Corporation has a royalty or working interest;
- the expectation of additional oil or natural gas that may be recovered from certain royalty properties in which the Corporation has an interest;
- supply and demand for oil and natural gas;
- the tax horizon and taxability of the Corporation;
- expectations regarding the ability to raise capital and add to reserves through acquisitions and development;
- the performance and characteristics of the oil and natural gas properties in which the Corporation has an investment;
- treatment under governmental regulatory regimes and tax laws;
- the expectation that our mineral title lands and gross overriding royalty interests will provide the majority of revenue;
- the intended focus of Freehold's activities undertaken by the Manager towards maximizing dividends to be paid to the Shareholders and acquiring appropriate assets to provide long-term growth in the value of Freehold;
- the expectation that the activities undertaken by Freehold will maximize value to the Shareholders;
- the expectation that Freehold may acquire additional royalties and other forms of oil and natural gas related assets or may participate in development activities on working interest properties that are primarily of a low risk nature and that have long-term value enhancement potential;
- the expectation that properties to be acquired may be operated by competent third parties or by Freehold;
- the expectation that with respect to new royalties, the purchase price paid by Freehold may include two components: an amount paid at closing for a royalty on existing production and an amount paid towards the

drilling of a predetermined number of future wells, which may be paid on completion of a specific operational event;

- that drilling activity on the Royalty Lands is anticipated to provide continued new sources of oil and natural gas Royalty Income in future years, with new wells and production therefrom reducing the rate at which production and Royalty Income would otherwise decline; and
- the expectation that approximately one-third of our 2017 capital budget will be allocated to Freehold's working interest, light oil, properties in Southeast Saskatchewan.

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:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- risks related to the environment and changing environmental laws;
- geological, technical, drilling, and processing problems;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry; and
- the other factors discussed under "*Risk Factors*".

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

- the impact of increasing competition;
- the general stability of the economic and political environment in which the Corporation has an interest in oil and natural gas properties;
- the timely receipt of any required regulatory approvals;
- the Manager's policies with respect to acquisitions and payments of dividends;
- the ability of the Manager to obtain qualified staff, equipment and services in a timely and cost efficient manner;
- drilling results;
- the ability of the operator of the projects that Freehold has an interest in to operate the field in a safe, efficient and effective manner;
- the continued development of the lands in which the Corporation has a royalty interest;
- that third parties such as royalty payors, operators of the lands in which the Corporation has a working interest and other contractual counterparties will satisfy their obligations as required;
- the ability of the Corporation to obtain financing on acceptable terms;
- field production rates and decline rates;
- the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration;
- the performance and characteristics of the oil and natural gas properties in which the Corporation has an interest;
- the timing and costs of pipeline, storage and facility construction and expansion and the ability of the operator of the properties in which the Corporation has an interest to secure adequate product transportation;
- future oil and natural gas prices;
- currency, exchange and interest rates;
- participation levels in the dividend reinvestment plan of Freehold;
- the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation has an interest in oil and natural gas properties; and

- the ability of the operator of the properties in which the Corporation has an interest to successfully market its oil and natural gas products. See "*Reserves Data – Significant Factors and Uncertainties*".

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"). We use 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 oil and natural gas reserve information contained in this AIF has been prepared and presented in accordance with National Instrument 51-101. The actual oil and natural gas reserves and future production will be greater than or less than the estimates provided in this AIF. The estimated future net revenue from the production of the disclosed oil and natural reserves does not represent the fair market value of these reserves.

GLOSSARY OF TERMS

In this AIF, the following terms shall have the meanings set forth below, unless otherwise indicated:

"**1872348**" means 1872348 Alberta Ltd., a corporation incorporated under the ABCA, a wholly-owned subsidiary of the Corporation and trustee of FHT.

"**ABCA**" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

"**Anderson**" has the meaning ascribed thereto under the heading "*General Development of Business – Year Ended December 31, 2015*".

"**Board of Directors**" means the Board of Directors of Freehold.

"**Canpar**" means Canpar Holdings Ltd., a wholly-owned subsidiary of the CN Pension Trust Funds.

"**CN Pension Trust Funds**" means the pension trust funds for employees of Canadian National Railway Company.

"**COGE Handbook**" means the "Canadian Oil and Gas Evaluation Handbook" prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society), as amended from time to time.

"**Common Shares**" means the common shares of Freehold.

"**Deferred Share Unit Plan**" means the deferred share unit plan for non-management directors of Freehold whereby fully vested Deferred Share Units are granted annually and dividends to Shareholders declared by the Corporation prior to redemption are assumed to be reinvested on behalf of the directors in notional units on the date of dividends.

"Deferred Share Units" means the deferred share units of the Corporation issued pursuant to the Deferred Share Unit Plan that are redeemable for Common Shares any time after the retirement of a member of the Board of Directors.

"Dodsland Viking GORR" has the meaning ascribed thereto under the heading *"General Development of Business - Year Ended December 31, 2015"*.

"DRIP" means the dividend reinvestment plan of Freehold.

"FHT" means Freehold Holdings Trust, a commercial trust formed under the laws of Alberta.

"Freehold", "us", "we", "our" or the **"Corporation"** means Freehold Royalties Ltd., a corporation amalgamated under the ABCA. All references to "Freehold", "us", "we", "our" or the "Corporation", unless the context otherwise requires, are references to Freehold Royalties Ltd., its predecessors, its subsidiaries and partnerships.

"Governance Agreement" means the governance agreement between the Manager and Freehold dated as of December 31, 2010.

"Gross" or **"gross"** means:

- in relation to production and reserves, our working interest (operating and non-operating) share before deduction of royalties and without including our royalty interests;
- in relation to wells, the total number of wells in which we have an interest; and
- in relation to properties, the total area of properties in which we have an interest.

"Husky Acquisition" has the meaning ascribed thereto under the heading *"General Development of Business – Year Ended December 31, 2016"*.

"Management Agreement" means the fourth amended and restated agreement dated November 9, 2015 among the Manager, Rife, the Corporation, FHT and the Partnership, which amended and restated the Original Management Agreement, pursuant to which the Manager provides management services to the Corporation, FHT and the Partnership.

"Management Fee" means the fee payable to the Manager pursuant to the Management Agreement.

"Manager" means Rife Resources Management Ltd., a wholly-owned subsidiary of Rife.

"Mineral Title and Royalty Package" has the meaning ascribed thereto under the heading *"General Development of Business – Year Ended December 31, 2015"*.

"Net" or **"net"** means:

- in relation to production and reserves, our working interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interests;
- in relation to wells, the number of wells obtained by aggregating our working interest in each of its gross wells; and
- in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest owned by us.

"New Anderson" has the meaning ascribed thereto under the heading *"General Development of Business – Year Ended December 31, 2015"*.

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

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

"Original Management Agreement" means the management agreement dated November 25, 1996 among the Manager, Freehold Resources Ltd., and Freehold Royalty Trust, as amended and restated by the first amended and

restituted management agreement dated May 10, 2006 among the Manager, Freehold Resources Ltd., and Freehold Royalty Trust, as amended and restated by the second amended and restated management agreement dated January 1, 2011 among the Manager, Freehold, Freehold Resources Ltd., and the Partnership, as amended and restated by the third amended and restated management agreement dated January 23, 2015 among the Manager, Freehold, FHT, and the Partnership.

"Partnership" means Freehold Royalties Partnership, a general partnership formed under the laws of Alberta.

"Penn West" has the meaning ascribed thereto under the heading *"General Development of Business – Year Ended December 31, 2015"*.

"Proved" and **"probable"** reserves have the meanings given to those terms under *"Reserves Data - Disclosure of Reserves Data"*.

"Rife" means Rife Resources Ltd., a wholly-owned subsidiary of the CN Pension Trust Funds.

"Royalty Income" means income to the Corporation from its royalties in oil, natural gas, NGL and potash resources.

"Royalty Lands" means the lands from which the Corporation derives Royalty Income.

"Seaton-Jordan" means Seaton-Jordan & Associates Ltd., independent land evaluation specialists of Calgary, Alberta.

"Shareholders" means the holders from time to time of Common Shares.

"Tax Act" means the *Income Tax Act* (Canada) and the regulations thereunder.

"Trimble" means Trimble Engineering Associates Ltd., independent qualified reserves evaluators of Calgary, Alberta.

"Trimble Report" means the report dated January 23, 2017 prepared by Trimble, evaluating the oil, natural gas, natural gas liquids, and sulphur reserves attributable to the Corporation as at December 31, 2016.

"TSX" means the Toronto Stock Exchange.

Abbreviations

AECO	reference pricing point for natural gas at a natural gas storage facility near the Alberta-Saskatchewan border
API	American Petroleum Institute
°API	the measure of the density of liquid petroleum products derived from a specific gravity
bbl and bbls	barrel and barrels, respectively, each barrel representing 34.972 imperial gallons or 42 U.S. gallons
bbls/d	barrels per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
Mbbls	one thousand barrels
Mboe	one thousand barrels of oil equivalent
MMbbls	one million barrels
MMboe	one million barrels of oil equivalent
MMBtu	one million British Thermal Units
Mcf	one thousand cubic feet
Mcf/d	one thousand cubic feet per day
MMcf	one million cubic feet
MMcf/d	one million cubic feet per day
NGL	natural gas liquids
WTI	West Texas Intermediate

Conversion Factors

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.4047
hectares	acres	2.471

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

CORPORATE STRUCTURE

General

Freehold is a dividend paying oil and gas corporation based in Calgary, which, directly or indirectly, acquired all of the assets and assumed all of the liabilities of Freehold Royalty Trust pursuant to a plan of arrangement completed on January 1, 2011.

On January 23, 2015, Freehold completed a restructuring pursuant to which it amalgamated first with its wholly-owned subsidiary, 1851328 Alberta Ltd. (formerly Anderson Energy Ltd.), and subsequently with another wholly owned subsidiary, Freehold Resources Ltd. The articles and by-laws of Freehold were not amended as a result of the amalgamation.

Freehold enables its Shareholders to participate in the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold, FHT and the Partnership. The head, principal and registered office of Freehold is located at Suite 400, 144 – 4th Avenue SW, Calgary, Alberta, T2P 3N4.

Rife Resources Management Ltd.

The Manager was incorporated under the *Corporations Act* (Ontario) on March 5, 1968 under the name "75-89 Gosford Limited" and continued under the *Canada Business Corporations Act* on April 20, 1979. The Manager changed its name to "Rife Resources Management Ltd." on October 1, 1996. Pursuant to the Management Agreement, Freehold, FHT and the Partnership retained the Manager for the purposes of identifying, evaluating and assisting with the acquisition, disposition and ongoing management and administration of the royalties, working interest properties and other oil, natural gas and potash resources held by Freehold, FHT and the Partnership. The head, principal and registered office of the Manager is located at Suite 400, 144 – 4th Avenue SW, Calgary, Alberta, T2P 3N4.

Pursuant to an agreement between Rife and the Manager, Rife provides the Manager, which is a wholly-owned subsidiary of Rife, on a contract basis, with all necessary personnel, equipment and facilities required to provide management and operational services to Freehold, FHT and the Partnership on a cost recovery basis. Freehold benefits from the fact that Rife has been in operation for more than 30 years and many of Rife's personnel have extensive experience managing the assets underlying Freehold's royalty and working interests. In addition, Rife manages two private entities that are also engaged in oil and gas operations and as a result Rife has assembled a diversified and experienced staff to manage the assets of Freehold. These organizational and synergistic benefits are advantageous to Shareholders. Rife and the Manager also ensure that Freehold receives priority to consider acquisition opportunities. In addition, the Management Fee paid to the Manager is paid in Common Shares, which the Board believes aligns the interests of the Manager with the interests of the Shareholders. Based on these factors, the Board believes that maintaining Freehold's relationship with the Manager is in the best interests of Freehold.

Pursuant to the Governance Agreement, the Manager is entitled to nominate for election two individuals as directors of Freehold provided that the Manager and its affiliates, including the CN Pension Trust Funds, hold 10% or more of the issued and outstanding Common Shares. If the Manager and its affiliates hold less than 10% of the issued and outstanding Common Shares, the Manager will have the right to nominate for election one individual as a director of Freehold. If the individuals nominated by the Manager fail to get elected or if the Manager ceases to hold any Common Shares (in which case the Manager will not have the right to nominate any individuals as directors of Freehold) but continues to act as manager of Freehold pursuant to the Management Agreement, the Governance Agreement will provide the Manager with the right to have an observer present at all meetings of directors of Freehold. The CN Pension Trust Funds currently holds, directly or indirectly, approximately 21.5% of the outstanding Common Shares and as a result, has the right to nominate two individuals as directors of Freehold.

Freehold Holdings Trust

FHT is a commercial trust formed under the laws of Alberta. All of the issued and outstanding trust units of FHT are held by Freehold and 1872348 is the trustee of FHT. The head office of FHT is located at Suite 400, 144 – 4th Avenue SW, Calgary, Alberta, T2P 3N4.

1872348 Alberta Ltd.

All of the issued and outstanding shares of 1872348 are held by Freehold. The head, principal and registered office of 1872348 is located at Suite 400, 144 – 4th Avenue SW, Calgary, Alberta, T2P 3N4.

Freehold Royalties Partnership

The Partnership is a general partnership formed under the laws of Alberta. On December 13, 2010, the Partnership changed its name from "Petrovera Resources" to "Freehold Royalties Partnership". Freehold and FHT are the general partners of the Partnership. Freehold is the managing partner of the Partnership. The head office of the Partnership is located at Suite 400, 144 – 4th Avenue SW, Calgary, Alberta, T2P 3N4.

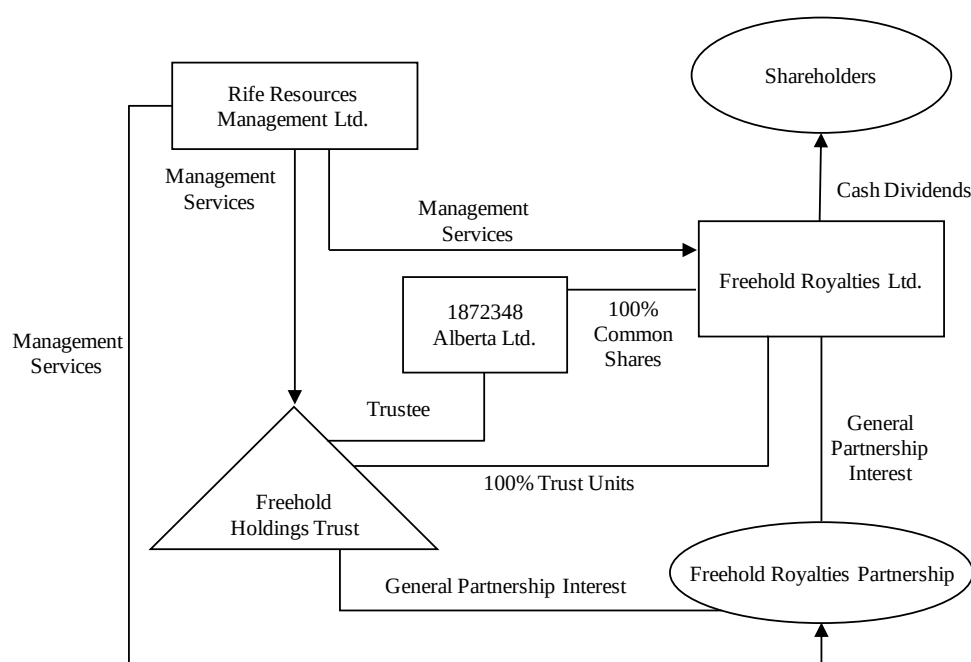
Structure of the Corporation

The following table provides the name, the percentage of voting securities owned by the Corporation and the jurisdiction of incorporation, continuance or formation of the Corporation's subsidiaries and partnerships, either direct or indirect, as at the date hereof.

	Percentage of Voting Securities (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation/ Formation
Freehold Royalties Partnership	100%	General Partnership	Alberta
Freehold Holdings Trust	100%	Commercial Trust	Alberta
1872348 Alberta Ltd.	100%	Corporation	Alberta

Organizational Structure of the Corporation

The following diagram sets forth the organizational structure of Freehold.



GENERAL DEVELOPMENT OF BUSINESS

The following is a summary description of the development of our business since January 1, 2014.

Year Ended December 31, 2014

On May 2, 2014, Freehold completed the acquisition of royalty interests on certain producing and non-producing lands in southeast Saskatchewan and Manitoba for \$107.6 million, including adjustments. The transaction was funded by our credit facilities. The acquisition added approximately 71,700 acres of mineral title lands to our land position in southeast Saskatchewan, while enhancing Freehold's near-term growth profile. 2013 average production associated with the acquired assets was approximately 470 boe/d.

On July 16, 2014, Freehold completed a \$120 million joint venture with a Canadian based company in the East Edson area of Alberta. As part of its \$120 million capital commitment, Freehold acquired a 50% royalty interest on current production within the joint venture area for \$50 million (effective July 1, 2014) and had a capital commitment of \$70 million pursuant to a farmout and royalty agreement. Through the joint venture, Freehold acquired a priority share of a defined production stream expecting to add approximately 1,100 boe/d (approximately 82% natural gas) flat volumes for an eight year period, declining at 10% per year thereafter.

On July 16, 2014, Freehold closed a bought deal offering issuing 4,900,000 Common Shares at a price of \$26.90 per share for gross proceeds of approximately \$132 million, which included the partial exercise of the over-allotment option granted to the underwriters. Concurrent with the closing of the bought deal offering, CN Pension Trust Funds invested approximately \$15 million in Freehold through the purchase of 557,621 Common Shares at a price of \$26.90

per share on a non-brokered private placement basis. Net proceeds from the bought deal offering and investment by CN Pension Trust Funds were used to fund the East Edson joint venture that closed on the same date and to repay a portion of bank indebtedness incurred as a result of previous acquisitions completed by Freehold.

On November 13, 2014, Freehold and Rife entered into two agreements whereby Freehold purchased a 5% gross overriding royalty on Rife's Soda Lake and Lindbergh assets. Total consideration associated with the two deals was \$10.1 million, including adjustments. The deal was funded through our credit facilities.

Year Ended December 31, 2015

On January 23, 2015, Freehold acquired all of the outstanding shares of Anderson Energy Ltd. ("**Anderson**") pursuant to a plan of arrangement under the ABCA for total consideration of \$35 million (subject to certain adjustments) with Freehold funding the deal through our existing credit facilities. Pursuant to the plan of arrangement, Anderson shareholders exchanged their shares for shares of a newly formed publicly listed company, Anderson Energy Inc. ("**New Anderson**"). In addition, prior to Freehold acquiring the outstanding shares, Anderson transferred certain assets and liabilities to New Anderson. The liabilities transferred to New Anderson included Anderson's liabilities and obligations for its outstanding convertible debentures. At the time of the transaction, one of the directors (Chairman) of Anderson was also a director of Freehold. Total net production included in Freehold's results from January 23, 2015 to December 31, 2015 was approximately 340 boe/d (96% natural gas).

Immediately following the completion of the acquisition of Anderson, Freehold completed a corporate restructuring pursuant to which Freehold first amalgamated with Anderson (after Anderson had changed its name to 1851328 Alberta Ltd.) and subsequently amalgamated with its wholly-owned subsidiary, Freehold Resources Ltd. In addition, pursuant to the restructuring, FHT was established and became a partner in the Partnership.

On May 6, 2015, Freehold completed an acquisition from Penn West Petroleum Ltd. ("**Penn West**") of two royalty packages for an aggregate purchase price of \$318 million, including adjustments. The effective date of the transactions was March 1, 2015. The first royalty package is an 8.5% gross overriding royalty covering 45,000 acres in Penn West's Dodsland area of Saskatchewan prospective for the Viking formation (the "**Dodsland Viking GORR**"). The second package is comprised of existing royalties and mineral title lands across a variety of plays within the Western Canadian Sedimentary Basin covering 280,000 acres (the "**Mineral Title and Royalty Package**"). Income from the Mineral Title and Royalty Package is split approximately 57% from gross overriding royalties and 43% from mineral title, with over 70% of existing production derived from southeast Saskatchewan and central Alberta. Total net production included in Freehold's results from May 6, 2015 to December 31, 2015 from the Dodsland Viking GORR and the Mineral Title and Royalty Package was over 1,500 boe/d (approximately 80% oil and NGLs).

In connection with the Penn West transactions, on May 6, 2015, Freehold closed a bought deal offering issuing 20,700,000 Common Shares at a price of \$18.00 per share for gross proceeds of approximately \$373 million, which included the full exercise of the over-allotment option granted to the underwriters. Concurrent with the closing of the bought deal offering, the CN Pension Trust Funds invested approximately \$33 million in Freehold through the purchase of 1,833,334 Common Shares at a price of \$18.00 per share on a non-brokered private placement basis. Freehold used a portion of the net proceeds from the bought deal financing and investment by the CN Pension Trust Funds to complete the Penn West transactions with the remainder to pay down a portion of outstanding bank indebtedness.

On November 9, 2015, Freehold, FHT and the Partnership entered into the Management Agreement with the Manager and Rife, which amended and restated the Original Management Agreement. On July 13, 2015 the Board of Directors established a special committee comprised of independent directors to review and consider the renewal or termination of the Original Management Agreement. The special committee retained financial advisors and independent legal counsel to provide financial and legal advice with respect to such matter. Following its review, the special committee concluded that it was in the best interests of the Corporation to amend the terms of the Original Management Agreement and proceeded to negotiate such amendments with Rife and the CN Pension Trust Funds, who also retained a financial advisor and independent legal counsel. As a result of the negotiations between Freehold and Rife a number of amendments were made to the Original Management Agreement, including amendments of the provisions relating to the payment of the Management Fee to the Manager and the provisions relating to termination. For additional details on the terms of the Management Agreement, see "*The Manager – Management Agreement*". In addition, the full text of the Management Agreement has been filed on SEDAR www.sedar.com.

Year Ended December 31, 2016

On May 25, 2016 Freehold closed an acquisition (the "**Husky Acquisition**") of an extensive suite of royalty production and fee lands from certain affiliates of Husky Energy Inc. for a purchase price of \$162 million, including adjustments. The Husky Acquisition, which was effective January 1, 2016, included approximately 2.5 million acres of royalty lands. Total net production included in Freehold's results from May 25, 2016 to December 31, 2016 from the Husky Acquisition was over 1,900 boe/d (approximately 65% natural gas).

In connection with the Husky Acquisition, on May 25, 2016 Freehold closed a bought deal offering issuing 16,428,900 Common Shares at a price of \$11.55 per share for gross proceeds of approximately \$190 million, which included the full exercise of the over-allotment option granted to the underwriters. Concurrent with the closing of the bought deal offering, the CN Pension Trust Funds invested approximately \$20 million in Freehold through the purchase of 1,732,000 common shares at a price of \$11.55 per share on a non-brokered private placement basis. Freehold used a portion of the net proceeds from the bought deal financing and investment by the CN Pension Trust Funds to complete the Husky Acquisition with the remainder used to pay down a portion of outstanding bank indebtedness.

Recent Developments

In February 2017, Freehold closed a \$34 million acquisition of various gross overriding royalties and mineral title lands in the greater Dodsland area of Saskatchewan. The acquisition is expected to add approximately 170 boe/d of production in 2017 (after closing) and 32,000 acres of royalty land including 6,500 net acres of mineral title.

Significant Acquisitions

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

BUSINESS OF THE CORPORATION

Overview

Freehold is an Alberta-based, dividend-paying corporation with a focus on royalty assets. Freehold receives revenue from properties as oil, natural gas, and potash are produced. Freehold has a diverse production base, with royalty payments from over 40,000 wells, and working interests in more than 1,800 oil and natural gas wells throughout western Canada. This includes significant mineral title and gross overriding royalty interests that will provide the majority of revenue. Royalties offer the benefit of sharing in production, without exposure to the capital, operating and environmental costs associated with oil, natural gas, and potash production. Oil, natural gas, and potash are finite resources. Over time, reserves are depleted and capital investment is required to sustain production and cash flow. Freehold replaces production by encouraging producers to drill on their land and by acquiring royalty interests.

Management Policies and Acquisition Strategy

The Manager manages Freehold, FHT and the Partnership in accordance with the Management Agreement. The Manager utilizes Rife's staff's extensive experience and employs prudent oil and gas business practices to increase the assets of Freehold through the acquisition of royalty interest oil and natural gas properties.

Freehold may, directly or indirectly through its subsidiaries and partnerships, acquire additional royalties and other forms of oil and natural gas related assets or may participate in development activities on working interest properties that are primarily of a low risk nature and that have long-term value enhancement potential. Properties to be acquired are operated by competent third parties or by Freehold.

Freehold's acquisition strategy targets individual properties, or groups of properties with a focus on royalty interests, to provide long-term growth in value. The key criteria are:

- quality assets;
- attractive returns;

- acceptable risk profile; and
- long economic life.

These criteria serve as guidelines for the Manager on presenting acquisitions for approval by the Board of Directors. The Board of Directors may vary these criteria for any particular acquisition based on the Manager's recommendations and consideration of the qualitative aspects of the subject properties.

The acquisition of additional royalties by Freehold includes existing contractual royalties and newly created royalties. With respect to new royalties, the purchase price paid by Freehold may include two components: an amount paid at closing for a royalty on existing production and an amount paid towards the drilling of a predetermined number of future wells, which may be paid on completion of a specific operational event.

RESERVES DATA

The statement of reserves data and other oil and natural gas information of the Corporation is set forth below (the "**Statement**"). The effective date of the Statement is December 31, 2016, and the preparation date of the Statement is January 23, 2017.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Reserves Data and Other Information in Form 51-101F3 are attached as Appendices A and B, respectively.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by an independent qualified reserves evaluator, Trimble, with an effective date of December 31, 2016 contained in the Trimble Report. The Reserves Data summarizes the crude oil, natural gas and natural gas liquids of Freehold and the net present values of future net revenue for these reserves using forecast prices and costs. Trimble also evaluated certain sulphur reserves of Freehold; however, as such sulphur reserves are immaterial to Freehold they have not been presented herein. The Trimble Report has been prepared in accordance with NI 51-101 and the standards and reserves definitions contained in the COGE Handbook. Information not required by NI 51-101 has been presented to provide continuity and additional information that we believe is important to the readers of this information. Freehold engaged Trimble to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Freehold's reserves are in Canada and, specifically, in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, and Ontario.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Freehold's crude oil, natural gas and natural gas liquids provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids may be greater than or less than the estimates provided herein.

**SUMMARY OF OIL AND GAS RESERVES
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS⁽¹⁾⁽²⁾**

Reserves Category	Light & Medium Crude Oil		Tight Oil		Heavy Crude Oil	
	Gross (Mbbbls)	Net (Mbbbls)	Gross (Mbbbls)	Net (Mbbbls)	Gross (Mbbbls)	Net (Mbbbls)
Proved						
Developed producing	1,173	5,401	153	744	381	3,242
Developed non-producing	61	56	78	61	-	7
Undeveloped	62	1,565	-	280	-	20
Total proved	1,296	7,021	232	1,084	381	3,269
Probable	1,072	3,929	303	576	323	1,600
Total proved plus probable	2,368	10,950	534	1,660	704	4,869

Reserves Category	Conventional Natural Gas		Coal Bed Methane		Shale Gas	
	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)
Proved						
Developed producing	3,462	53,876	1,270	1,234	-	9
Developed non-producing	1,123	1,013	1,060	961	101	92
Undeveloped	121	16,193	-	-	-	1,254
Total proved	4,706	71,082	2,330	2,195	101	1,356
Probable	2,926	33,930	1,320	1,218	63	638
Total proved plus probable	7,632	105,012	3,650	3,413	164	1,994

Reserves Category	Natural Gas Liquids		Total Oil Equivalent	
	Gross (Mbbbls)	Net (Mbbbls)	Gross (Mboe)	Net (Mboe)
Proved				
Developed producing	191	1,193	2,687	19,766
Developed non-producing	36	27	556	495
Undeveloped	3	354	86	5,126
Total proved	230	1,574	3,329	25,387
Probable	153	824	2,569	12,894
Total proved plus probable	383	2,398	5,897	38,280

(1) Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include royalties receivable. Net reserves are comprised of working interests minus royalties payable plus royalties receivable. The majority of the Corporation's assets are royalty interests. This causes our gross reserves to be lower than our net reserves and may hinder an investor's ability to compare our reserves with others in our industry.

(2) Columns may not add due to rounding.

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

Reserves Category	Before Income Taxes, Discounted at (% per year)				
	0%	5%	10%	15%	20%
	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)
Proved					
Developed producing	862,343	642,367	516,515	435,613	379,273
Developed non-producing	3,332	2,861	2,533	2,289	2,099
Undeveloped	235,534	173,068	132,650	104,920	85,062
Total proved	1,101,209	818,296	651,698	542,822	466,434
Probable	661,014	357,849	228,882	161,962	122,451
Total proved plus probable	1,762,224	1,176,145	880,580	704,784	588,885

Reserves Category	After Income Taxes, Discounted at (% per year)				
	0%	5%	10%	15%	20%
	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)
Proved					
Developed producing	862,343	642,367	516,515	435,613	379,273
Developed non-producing	3,332	2,861	2,533	2,289	2,099
Undeveloped	204,859	152,959	119,057	95,487	78,365
Total proved	1,070,535	798,187	638,104	533,388	459,738
Probable	490,677	265,217	170,847	122,423	93,990
Total proved plus probable	1,561,211	1,063,404	808,952	655,812	553,727

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS**

(\$000s)	Reserves Category	
	Proved	Proved Plus Probable
Royalty Income	1,068,308	1,683,290
Revenue from working interest properties	188,664	366,935
Royalty expense on working interest properties	(19,835)	(48,650)
Operating costs	(117,061)	(205,871)
Development costs	(2,572)	(13,056)
Abandonment and reclamation costs ⁽¹⁾	(16,294)	(20,425)
Future net revenue before income taxes	1,101,209	1,762,224
Future income taxes	(30,674)	(201,012)
Future net revenue after income taxes	1,070,535	1,561,211

(1) Reflects estimated abandonment and reclamation for all wells (both existing and undrilled wells) that have been attributed reserves. See "Environmental Obligations – Additional Information Concerning Abandonment and Reclamation Costs".

**FUTURE NET REVENUE
BY PRODUCT TYPE
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS**

Reserves Category	Product Type	Future Net Revenue Before Income Taxes Discounted at 10% per year (\$000s)	Unit Value ⁽¹⁾ (\$)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	305,620	43.53/bbl
	Tight Oil (including solution gas and other by-products)	45,871	42.32/bbl
	Heavy Crude Oil (including solution gas and other by-products)	119,238	36.48/bbl
	Conventional Natural Gas (including by-products)	179,020	2.81/Mcf
	Coal Bed Methane (including by-products)	41	0.02/Mcf
	Shale Gas (including by-products)	1,907	1.41/Mcf
	Total Proved	651,698	25.67/boe
Proved plus probable	Light and Medium Crude Oil (including solution gas and other by-products)	424,957	38.81/bbl
	Tight Oil (including solution gas and other by-products),	59,591	35.90/bbl
	Heavy Crude Oil (including solution gas and other by-products)	158,079	32.47/bbl
	Conventional Natural Gas (including by-products)	234,488	2.52/Mcf
	Coal Bed Methane (including by-products)	797	0.23/Mcf
	Shale Gas (including by-products)	2,668	1.34/Mcf
	Total Proved Plus Probable	880,580	23.00/boe

(1) The Unit Value is calculated by dividing the discounted Future Net Revenue by the net reserves for the principal product of the Product Type.

Definitions and Other Notes

- Columns may not add due to rounding.
- The oil, natural gas and natural gas liquids reserves estimates presented in the Trimble Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below.

Reserve Categories

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

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

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

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

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

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

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

- (a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
 - (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
 - (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Levels of Certainty for Reported Reserves

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

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

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

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

3. Forecast Prices and Costs

Forecast prices and costs are those:

- (a) generally acceptable as being a reasonable outlook of the future; and
- (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Freehold is legally bound by a contractual or other obligation to supply a physical product, including those

for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

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

**FORECAST PRICES USED IN ESTIMATES
AS OF DECEMBER 31, 2016**

Year	Oil					Natural Gas	Natural Gas Liquids				Inflation Rate	Exchange Rate
	Canadian		Hardisty	Hardisty	Western	AECO	Propane	Butane	Pentane			
	WTI	Light	Heavy	Bow	Canadian	30 Day						
	Cushing	Sweet	12° API	River	Select	Spot						
	Oklahoma	40° API	24.9° API	20.5° API	MMBtu	bbl				bbl		
	\$US/ bbl	\$Cdn/ bbl	\$Cdn/ bbl	\$Cdn/ bbl	\$Cdn/ bbl	\$Cdn/ MMBtu	\$Cdn/ bbl	\$Cdn/ bbl	\$Cdn/ bbl	%/ Year	\$US/\$ Cdn	
2017	55.00	65.58	48.53	53.77	53.12	3.44	22.74	47.60	67.95	2.00	0.78	
2018	65.00	74.51	56.63	62.59	61.85	3.27	28.04	55.49	75.61	2.00	0.82	
2019	70.00	78.24	59.46	65.72	64.94	3.22	30.64	57.65	78.82	2.00	0.85	
2020	71.40	80.64	61.29	67.74	66.93	3.91	32.27	58.80	80.47	2.00	0.85	
2021	72.83	82.25	62.51	69.09	68.27	4.00	33.95	59.98	82.15	2.00	0.85	
2022	74.28	83.90	63.76	70.47	69.64	4.10	35.68	61.18	83.86	2.00	0.85	
2023	75.77	85.58	65.04	71.88	71.03	4.19	37.46	62.40	85.61	2.00	0.85	
2024	77.29	87.29	66.34	73.32	72.45	4.29	39.30	63.65	87.39	2.00	0.85	
2025	78.83	89.03	67.67	74.79	73.90	4.40	41.19	64.92	89.21	2.00	0.85	
2026	80.41	90.81	69.02	76.28	75.38	4.50	43.13	66.22	91.07	2.00	0.85	
2027	82.02	92.63	70.40	77.81	76.88	4.61	45.14	67.54	92.96	2.00	0.85	
Thereafter, per year:												
	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%	2.00	0.85	

The following table provides the historical weighted average prices realized by Freehold for the year ended December 31, 2016:

**FREEHOLD WEIGHTED AVERAGE PRICES
YEAR ENDED DECEMBER 31, 2016**

	Light and Medium Crude Oil (\$/bbl)	Heavy Crude Oil (\$/bbl)	Natural Gas (\$/Mcf)	Natural Gas Liquids (\$/bbl)	Oil Equivalent (\$/boe)
Freehold weighted average price	46.91	32.39	1.81	29.58	28.37

4. "Development well" means a well drilled inside the established limits of an oil and natural gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
5. "Exploratory well" means a well that is not a development well, a service well or a stratigraphic test well.
6. "Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:
 - (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, natural gas lines and power lines, to the extent necessary in developing the reserves;

- (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
 - (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
 - (d) provide improved recovery systems.
7. "Exploration costs" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
- (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;
 - (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
 - (c) dry hole contributions and bottom hole contributions;
 - (d) costs of drilling and equipping exploratory wells; and
 - (e) costs of drilling exploratory type stratigraphic test wells.
8. "Service well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

9. Future Development Costs

The following table sets forth development costs deducted in the estimation of Freehold's future net revenue attributable to the reserve categories noted below, based on forecast prices and costs:

Year	Forecast Prices and Costs	
	Proved Reserves (undiscounted) (\$000s)	Proved Plus Probable Reserves (undiscounted) (\$000s)
2017	-	5,102
2018	1,808	4,425
2019	-	2,121
2020	764	1,315
2021	-	-
Remainder	-	94
Total	2,572	13,057

The source of funding for future development costs will be internally generated cash flow, debt or a combination of both. Disclosed reserves and future net revenue are not expected to be materially affected by the costs of funding the future development expenditures.

10. The forecast price and cost assumptions assume the continuance of current laws and regulations.

11. The extent and character of all factual data supplied to Trimble were accepted by Trimble as represented. No field inspection was conducted.
12. The after-tax net present value calculation of the Corporation's reserves reflects the tax burden on the Corporation's properties on a standalone basis, utilizing our tax pools to the maximum depreciation rate as currently permitted. It does not consider the corporate-level tax situation, or tax planning. It does not provide an estimate of the value at the corporate level, which may be significantly different. See our financial statements and accompanying management's discussion and analysis for additional tax information.

Certain other terms used herein 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.

Reconciliation of Changes in Reserves

The table below is a reconciliation of gross reserves and is provided as a requirement of NI 51-101. 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 the majority of the Corporation's assets are royalty interests, they are excluded from this table. This hinders an investor's ability to compare our reserves to exploration and development companies. Therefore in addition to presenting the reconciliation using gross reserves, we have also presented the reconciliation using net reserves.

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

	Light and Medium Crude Oil			Tight Oil			Heavy Crude Oil		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2015	1,435	1,316	2,751	145	204	349	651	722	1,373
Production	(277)	-	(277)	(132)	-	(132)	(149)	-	(149)
Technical revisions	138	(242)	(104)	202	97	298	(112)	(392)	(504)
Extensions and improved recovery	49	20	69	24	9	33	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	(2)	(2)
Economic factors	(50)	(21)	(71)	(7)	(7)	(13)	(9)	(5)	(14)
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2016⁽¹⁾	1,296	1,072	2,368	232	303	534	381	323	704

	Conventional Natural Gas			Coal Bed Methane			Shale Gas		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2015	7,985	5,751	13,736	-	-	-	101	66	167
Production	(1,058)	-	(1,058)	(307)	-	(307)	-	-	-
Technical revisions	(2,126)	(2,867)	(4,993)	2,867	1,415	4,282	-	-	-
Extensions and improved recovery	165	58	223	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(83)	(62)	(145)	-	-	-	-	-	-
Economic factors	(177)	45	(131)	(230)	(95)	(325)	-	(3)	(3)
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2016⁽¹⁾	4,706	2,926	7,632	2,330	1,320	3,650	101	63	164

	Natural Gas Liquids			Total Oil Equivalent		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2015	207	157	364	3,786	3,368	7,154
Production	(66)	-	(66)	(851)	-	(851)
Technical revisions	87	(7)	80	438	(786)	(348)
Extensions and improved recovery	9	4	13	110	42	152
Acquisitions	-	-	-	-	-	-
Dispositions	(2)	(1)	(3)	(15)	(14)	(29)
Economic factors	(5)	-	(5)	(138)	(42)	(180)
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2016⁽¹⁾	230	153	383	3,329	2,569	5,897

(1) Columns may not add due to rounding.

The following reserve reconciliation table is provided as an aid to the investor. The table is based on net reserves and is consistent with our disclosure in previous years.

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

	Light and Medium Crude Oil			Tight Oil			Heavy Crude Oil		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2015	6,888	4,251	11,140	1,047	592	1,639	3,926	2,311	6,237
Production	(1,112)	-	(1,112)	(222)	-	(222)	(793)	-	(793)
Technical revisions	430	(764)	(334)	235	(21)	215	(357)	(921)	(1,278)
Extensions and improved recovery	104	38	142	18	7	25	108	30	138
Acquisitions	735	422	1,157	11	3	14	388	185	573
Dispositions	-	-	-	-	-	-	-	(2)	(2)
Economic factors	(25)	(19)	(43)	(5)	(5)	(11)	(3)	(3)	(6)
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2016⁽¹⁾	7,021	3,929	10,950	1,084	576	1,660	3,269	1,600	4,869

	Conventional Natural Gas			Coal Bed Methane			Shale Gas		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2015	56,564	30,526	87,089	216	73	289	1,524	697	2,221
Production	(10,485)	-	(10,485)	(294)	-	(294)	(1)	-	(1)
Technical revisions	4,993	(4,815)	179	2,426	1,214	3,640	(167)	(57)	(223)
Extensions and improved recovery	665	298	963	-	-	-	-	-	-
Acquisitions	19,565	7,932	27,498	54	14	68	-	-	-
Dispositions	(77)	(55)	(133)	-	-	-	-	-	-
Economic factors	(143)	44	(98)	(206)	(84)	(290)	-	(3)	(3)
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2016⁽¹⁾	71,082	33,930	105,012	2,195	1,218	3,413	1,356	638	1,994

	Natural Gas Liquids			Total Oil Equivalent		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2015	1,357	748	2,105	22,936	13,118	36,054
Production	(297)	-	(297)	(4,219)	-	(4,219)
Technical revisions	188	(80)	108	1,705	(2,395)	(689)
Extensions and improved recovery	37	19	56	378	144	522
Acquisitions	293	138	430	4,696	2,072	6,768
Dispositions	(1)	(1)	(2)	(14)	(12)	(26)
Economic factors	(3)	-	(3)	(95)	(34)	(129)
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2016⁽¹⁾	1,574	824	2,398	25,387	12,894	38,280

(1) Columns may not add due to rounding.

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards in the COGE Handbook.

At December 31, 2016, proved net undeveloped reserves assigned in the Trimble Report were 20.2% of the total proved net reserves assigned.

At December 31, 2016, probable net undeveloped reserves were 12.8% of the total proved plus probable net reserves assigned in the Trimble Report.

The light, medium and heavy crude oil net undeveloped reserves are expected to be developed over the next several years as commodity pricing permits. Development of the undeveloped natural gas and natural gas liquids net reserves will be dependent on commodity pricing and in certain circumstances it may be three or more years until they are developed. In most cases the development of undeveloped reserves is not within the control of Freehold as Freehold only holds a royalty interest in such reserves and therefore does not have control or influence on the development of such reserves.

The following tables set forth the proved undeveloped reserves and the probable undeveloped net reserves by product type, attributed to Freehold's assets for the years ended December 31, 2016, 2015, and 2014, based on forecast prices and costs:

INITIAL PROVED UNDEVELOPED NET RESERVES FIRST ATTRIBUTED BY YEAR FORECAST PRICES AND COSTS

Year	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)
2014	17	-	9,986	174
2015	1,657	-	2,414	112
2016	170	20	2,508	50
Total Booked for Current Year	1,844	20	17,447	354

INITIAL PROBABLE UNDEVELOPED NET RESERVES FIRST ATTRIBUTED BY YEAR FORECAST PRICES AND COSTS

Year	Light and Medium Crude Oil (Mbbls)	Heavy Crude Oil (Mbbls)	Conventional Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)
2014	329	26	6,831	119
2015	1,090	-	2,616	128
2016	251	80	3,667	73
Total Booked for Current Year	1,947	137	14,874	342

Significant Factors or Uncertainties

The reserve and recovery information contained in the Trimble Report are only estimates and the actual production and ultimate reserves may be greater or less than the estimates prepared by Trimble.

The value of the Common Shares will depend upon, among other things, the reserves attributable to the Corporation's properties. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the Corporation's properties will vary from estimates and those variations could be material. The reserve and cash flow information contained in this Statement represents estimates only. Reserves and estimated future net cash flow from the Corporation's properties have been evaluated by Trimble, an independent qualified reserves evaluator. Trimble considers a number of factors and makes assumptions when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation;
- assumptions about future commodity prices;
- assumptions about future production levels, development costs and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- future drilling on our royalty lands by third parties;
- timing and amount of capital expenditures;
- marketability of production;
- future prices of oil and natural gas;
- operating costs and royalties; and
- other government levies that may be imposed over the producing life of reserves.

These factors and assumptions were based on prices at the date the evaluation was prepared. If these factors and assumptions prove to be inaccurate, the actual results may vary materially from the reserve estimates. Many of these factors are subject to change and are beyond the Corporation's control. For example, the evaluation is based in part on the assumed success of exploitation activities intended to be undertaken in future years. Actual reserves and estimated cash flows will be less than those contained in the evaluation to the extent that such exploitation activities do not achieve the level of success assumed in the evaluation. Furthermore, cash flows may differ from those contained in the evaluation depending upon whether capital expenditures and operating costs differ from those estimated in the evaluation.

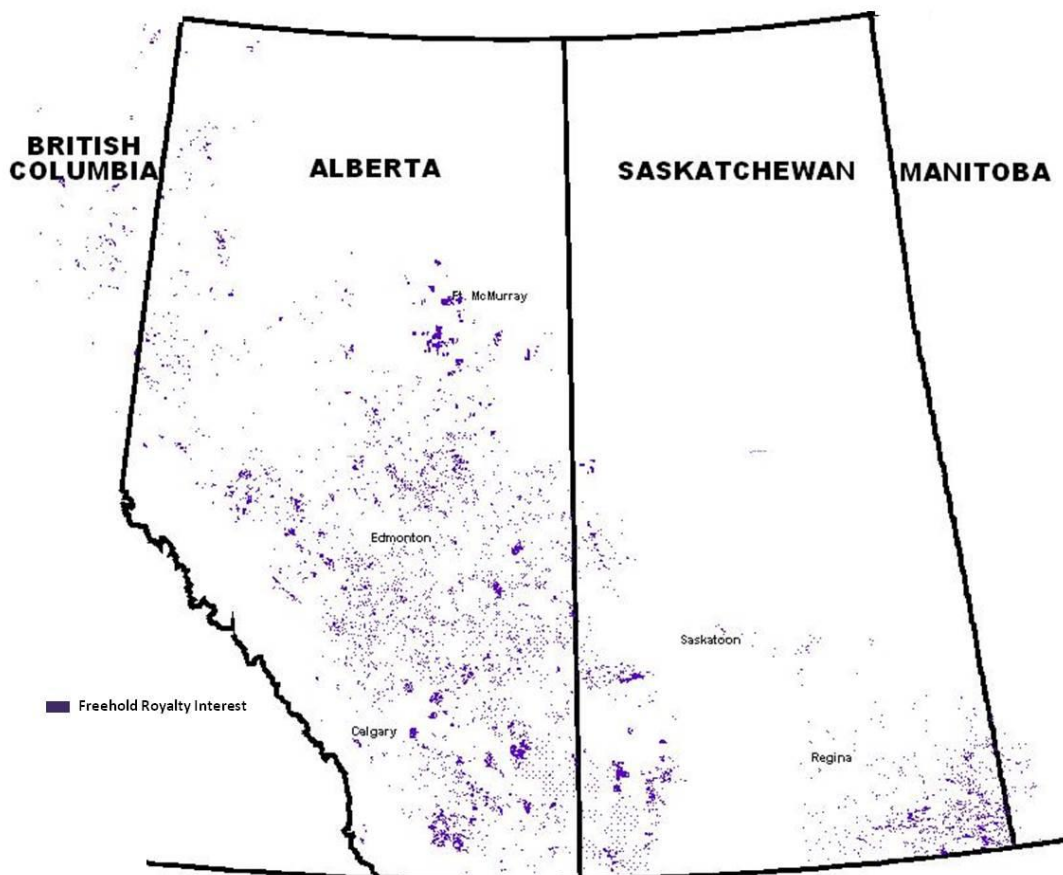
DESCRIPTION OF PROPERTIES

Freehold has oil and natural gas interests in producing and non-producing lands located in British Columbia, Alberta, Saskatchewan, Manitoba, and Ontario, encompassing approximately 6.1 million gross acres at December 31, 2016. Excluding the properties acquired pursuant to the Husky Acquisition, the majority of our land (70%) is in Alberta, with 22% in Saskatchewan, 3% in Ontario, 4% in British Columbia, and less than 1% in Manitoba. We also own royalty interests in eight potash mines in Saskatchewan.

Unless otherwise noted, the various acreage categories presented in this AIF (including acreage broken down by province, by undeveloped versus developed and by type of interest) do not include an additional 2.5 million gross acres of mineral title and royalty lands acquired pursuant to the Husky Acquisition in 2016. This additional acreage has not been released from Freehold's integration process for this reporting period and therefore has not yet been categorized.

Producing lands include Crown, freehold, unitized and non-unitized oil and natural gas and potash production. The properties are operated by experienced operators. Our top ten payors through year-end 2016 were: Apache Canada Ltd., Canadian Natural Resources Limited, Crescent Point Energy Partnership, Husky Oil Operations Limited, Manito Energy Inc., Penn West Petroleum, Perpetual Energy Operating Corp., Spartan Energy Corp., Teine Energy Ltd., and Tundra Oil & Gas Limited.

Approximately 96% of our gross land holdings are royalty interests, from which we derive the majority of our income.



In the following discussion, all references to reserves are net, utilizing forecast prices and costs, before tax. All references to royalty production are net, and all references to working interest production are gross. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Royalty Interests

The unique characteristics of royalties provide royalty holders with special commercial benefits not available to the working interest owner because the royalty holder enjoys the upside potential of the property with reduced risk. A royalty interest differs significantly from a working interest in that a holder of a royalty interest is generally not responsible for, and has no obligation to contribute additional funds for any purpose, including operating or capital costs, or environmental or reclamation liabilities; whereas a holder of a working interest is liable for its share of capital, operating and environmental costs, usually in proportion to its ownership percentage, and it receives its pro rata share of revenue.

The Corporation's royalty reserves are derived from: (i) leased mineral title lands that are owned by the Corporation and upon which the lessees pay lessor royalties to the Corporation; (ii) royalty assumption lands which are mineral title properties owned by third parties in respect of which royalties are reserved to the Corporation and which, by their terms, are expressed to be interests in land; and (iii) gross overriding royalty lands leased by third parties upon which

such third parties pay contractual royalties or net profits interests to the Corporation, which may or may not be interests in land. Mineral title and royalty assumption lands do not expire, while gross overriding royalties may expire at the end of the lease's productive life. Mineral title lands and royalty assumption lands derived from mineral titles are held in perpetuity.

Mineral Title Lands

Royalty revenue is derived from the royalties payable to the Corporation (lessor) in the form of lessor royalties through the lease documents issued to the companies (lessees) that have producing wells located thereon. In 2016, this category of land accounted for approximately 21% of our total royalty acreage and provided approximately 40% of our royalty revenue.

The Corporation has ownership interests in mineral titles ranging from 10% to 100% and recovers the applicable royalty, ranging from 10% to 22.5%, of all oil and natural gas products produced or sold from the leased lands. For example, if the Corporation's interest in a mineral title property is 50% and the royalty rate applicable to the lease is 20% then the Corporation would be entitled to receive the proceeds from the sale of 10% (50% x 20%) of the oil or natural gas produced for the period.

The Corporation's mineral title lands encompass approximately 700,000 acres, of which 79% are leased and 21% are unleased. The mineral title lands also include approximately 311,000 undeveloped acres, representing potential for future development. The majority of Freehold's unleased mineral title lands are in southeast Saskatchewan.

The Corporation also holds mineral title interests in potash, as described on page 27.

Royalty Assumption Lands

The Corporation holds royalty interests in approximately 91,000 acres of mineral title lands, of which approximately 20,000 acres are undeveloped. These mineral title properties, referred to as royalty assumption lands, are owned by a number of third party oil and gas companies in respect of which royalties (varying from 4.7% to 6.5%) have been reserved to the Corporation. As the royalty interests with respect to the royalty assumption lands are a title royalty representing, by their terms, an interest in land, these royalties are held in perpetuity. In 2016, this category of land accounted for approximately 3% of our total royalty acreage and provided approximately 1% of our royalty revenue.

Gross Overriding Royalty Lands

The Corporation holds gross overriding royalties in approximately 2.6 million acres, of which approximately 625,000 acres are undeveloped. The gross overriding royalties are contractual in nature and therefore are not held in perpetuity but rather expire upon the termination of the lease(s) or agreement(s) which generally occurs when production has ceased from the subject lands. These lands consist of properties leased by a number of third party oil and gas companies in respect of which contractual royalties or net profits interests have been reserved to the Corporation. In 2016, this category of land accounted for approximately 76% of our total royalty acreage and provided approximately 59% of our royalty revenue.

The granting of a gross overriding royalty usually arises as a result of: (i) providing capital in exchange for granting the royalty; or (ii) converting a participating interest in a joint venture relationship into a royalty. Gross overriding royalties are based on the proceeds from the sale of gross production and are generally free of any operating, capital and environmental costs.

Description of Royalty Lands

The Corporation's royalty interests represent a geologically and geographically diverse portfolio of properties. The Manager oversees this portfolio through multi-disciplined technical teams, each managing a geographic region.

The following table summarizes, by area, the Corporation's average royalty interest, net reserves and reserves value as at December 31, 2016, wells drilled, oil and natural gas production, and royalty revenue for 2016 for the Corporation's Royalty Lands:

Year ended December 31, 2016		Alberta West	Lloydminster	Saskatchewan East	Total
Average royalty interest ⁽¹⁾	(%)	2.7	5.4	1.3	2.4
Wells drilled	(gross)	88	64	129	281
Royalty income ⁽²⁾	(\$000s)	38,590	28,122	34,001	100,713
Average net daily production	(boe/d)	5,377	2,374	2,185	9,936
Oil and NGL	(bbls/d)	1,534	2,123	1,914	5,571
Natural gas	(Mcf/d)	23,064	1,504	1,621	26,189
Net proved reserves	(Mboe)	13,860	4,298	4,278	22,437
Oil and NGL	(Mbbls)	3,641	3,787	3,637	11,065
Natural gas	(MMcf)	61,316	3,066	3,849	68,230
Net proved plus probable reserves	(Mboe)	20,177	6,373	6,595	33,145
Oil and NGL	(Mbbls)	5,111	5,644	5,695	16,450
Natural gas	(MMcf)	90,400	4,374	5,399	100,172
Future Net Revenue ⁽¹⁾⁽²⁾					
Discounted at 10% per year	(\$000s)	358,084	228,135	232,869	819,087
	(% of total)	44	28	28	100

(1) Based on proved plus probable reserves and forecast prices as assigned in the Trimble Report.

(2) Excludes income from potash, interest and other.

The following table summarizes, by region, the gross royalty acreage with respect to the Corporation's Royalty Lands by region, as at December 31, 2016:

Area	Developed Gross Acres	Undeveloped Gross Acres ⁽¹⁾	Total Gross Acres
Alberta West	1,570,259	539,139	2,109,398
Lloydminster	399,895	128,151	528,046
Saskatchewan East	412,736	281,343	694,079
Potash	16,939	7,332	24,271
Total	2,399,829	955,965	3,355,794
Additional Lands ⁽²⁾			2,500,000
Total Royalty Acres			5,855,794

(1) Undeveloped royalty lands are lands without producing or potentially producing wells.

(2) Pending release from Freehold's integration process, the divisions and categories of approximately 2,500,000 additional gross acres of mineral title and royalty lands acquired pursuant to the Husky Acquisition in 2016 are undetermined at time of reporting.

Alberta West

The Alberta West region includes all of Freehold's royalty interests in British Columbia and Alberta, except for lands in the Lloydminster region. This region contains 63% of Freehold's total royalty acreage, 54% of royalty production, and 61% of net proved plus probable reserves for the royalty interest properties. In 2016, industry operators drilled 88 gross wells on the Royalty Lands in this region. On a boe basis, production increased 26% in 2016 and was 29% oil and NGL and 71% natural gas. The oil production is 91% light and medium quality crude.

2016 royalty drilling primarily comprised of targets in the liquids rich and oil plays of the Cardium, Mannville, Montney and Devonian. Operators continue to use and refine horizontal multi-stage fracture stimulation techniques to exploit these low permeability reservoirs.

Lloydminster

The Lloydminster region encompasses the portions of Alberta and Saskatchewan that extend from Township 31 to Township 65, bounded on the east by Range 13, west of the Third Meridian, and bounded on the west by Range 15, west of the Fourth Meridian. This region contains 16% of Freehold's total royalty acreage, 24% of royalty production, and 19% of net proved plus probable royalty interest reserves. In 2016, industry operators drilled 64 gross wells on the Royalty Lands in this region. On a boe basis, production increased 9% in 2016 and was 89% oil and NGL (72% of the oil is heavy) and 11% natural gas.

In 2016, 23% of total royalty drilling occurred in this region. Traditionally, the primary target for operators on the Royalty Lands in the Lloydminster region is Mannville Group heavy oil. The oil is exploited with vertical wells using CHOPS (cold heavy oil production with sand) technology or with horizontal wells.

In 2015, Freehold acquired the Dodsland Viking GORR from Penn West. The north half of the Viking Dodsland oil resource play falls within the lower Lloydminster region. The Dodsland Viking GORR consists of an 8.5% gross overriding royalty covering 45,000 acres in the Viking resource play in the Dodsland area of Saskatchewan. In 2016, 38 gross Viking horizontal wells were drilled accounting for 59% of the total royalty wells drilled in the Lloydminster area. The Viking resource play is a light oil development play and expansion here increases our overall exposure to high quality, more valuable, light oil.

Saskatchewan East

The Saskatchewan East region includes all of Freehold's royalty interests in Saskatchewan (except for lands in the Lloydminster region) and Manitoba, and minor royalty interests in southern Ontario. This region contains 21% of Freehold's total royalty acreage, 22% of royalty production, and 20% of net proved plus probable royalty interest reserves. In 2016, industry operators drilled 129 gross wells on the Royalty Lands in this region. On a boe basis, production increased 18% in 2016 and was 88% oil and NGL and 12% natural gas.

In 2016, 46% of total royalty drilling occurred in this region. In Saskatchewan and Manitoba, production is almost entirely light to medium oil recovered primarily from Viking marine sandstone reservoirs, Mississippian subcrop traps, Jurassic Shaunavon and Bakken reservoirs.

As discussed in the Lloydminster area, the south half of the Viking Dodsland oil resource play falls within the Saskatchewan East region. In 2016, 23 gross Viking horizontal wells were drilled accounting for 18% of the total royalty wells drilled in the Saskatchewan East region.

The 2016 Husky Acquisition gave greater exposure to the Shaunavon play. In 2016, 13 gross horizontal wells were drilled in the shallow marine upper Shaunavon and microcrystalline limestone Lower Shaunavon representing 10% of the total royalty wells drilled in this region.

Potash

The Corporation's potash acreage inventory increased to approximately 24,000 gross acres in 2016 from approximately 22,900 gross acres in 2015. This increase is primarily the result of leases being issued by the Corporation on its mineral title to the operator of a new potash mine bringing to eight the total number of potash mines in which the Corporation has issued leases to the various mine operators. The Corporation's leases are included in larger potash units which cover the total mine areas.

The potash mines from which the Corporation receives royalties are operated by Potash Corporation of Saskatchewan and The Mosaic Company. In 2016 the Corporation received approximately \$1.4 million from the production of approximately twelve tonnes per day of potash. As the Corporation's minor interests in potash reserves are not material to the Corporation, a recent independent evaluation of the Corporation's potash reserves has not been obtained.

Undeveloped Royalty Lands

The undeveloped Royalty Lands are lands without producing, or potentially producing, wells totalling approximately 956,000 gross acres. Potential exists on these lands for drilling non-unitized zones within producing units, drilling or completing additional zones, infill drilling by reducing well spacing (e.g. 160 acre to 80 acre spacing in the case of an oil well), optimizing drilling locations within spacing units and horizontal drilling. If a well is drilled on lands adjacent to Royalty Lands where we own the mineral title and that well is producing from a formation in which the Corporation has an interest but that is not producing on the Royalty Lands, generally the Corporation has the right to require the lessee of the mineral title to either: (a) drill a well on an undrilled spacing unit on the Royalty Lands; (b) pay a compensatory royalty; or (c) surrender the respective formation.

Drilling Activity

Freehold is not responsible for any drilling or development activity or expenditures with respect to the Royalty Lands leased to third parties, but receives Royalty Income from successful wells. Drilling activity on the Royalty Lands is anticipated to continue to provide new sources of oil and natural gas Royalty Income in future years, with new wells, and production therefrom, reducing the rate at which production and Royalty Income would otherwise decline. The extent of drilling and development activity in future years by the operators cannot be predicted.

The following table summarizes the drilling activity conducted by lessees on the Royalty Lands for the two most recently completed fiscal years. During this period, 662 unitized and non-unitized development wells were drilled. One natural gas well was drilled in the East Edson joint venture during this period. The drilling activity on the Royalty Lands in the last two fiscal years may not be indicative of future activity.

Years Ended December 31 ⁽¹⁾ (gross wells)	2016		2015	
	Unitized	Non-Unitized	Unitized	Non-Unitized
Oil wells	54	146	118	210
Natural gas wells	-	9	-	16
Service/other wells	5	64	-	37
Dry and abandoned wells	-	3	-	-
Total	59	222	118	263
Success rate	100%	99%	100%	100%

(1) Includes all drilling on properties acquired during the year.

Reconciliation of Royalty Lands Reserves⁽¹⁾

The following table provides a summary of the changes in the net crude oil and natural gas reserves on our Royalty Lands during 2016, based on forecast prices and costs:

	Light and Medium Crude Oil			Tight Oil			Heavy Crude Oil		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbbls)	(Mbbbls)	(Mbbbls)	(Mbbbls)	(Mbbbls)	(Mbbbls)	(Mbbbls)	(Mbbbls)	(Mbbbls)
December 31, 2015	5,606	3,142	8,749	931	429	1,360	3,372	1,722	5,094
Production	(873)	-	(873)	(117)	-	(117)	(668)	-	(668)
Technical revisions	317	(563)	(246)	75	(98)	(23)	(281)	(610)	(891)
Extensions and improved recovery	62	22	84	-	-	-	108	30	138
Acquisitions	735	422	1,157	11	3	14	388	185	573
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2016⁽²⁾	5,848	3,023	8,871	900	334	1,234	2,918	1,327	4,246

	Conventional Natural Gas			Coal Bed Methane			Shale Gas		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcuf)	(MMcuf)	(MMcuf)	(MMcuf)	(MMcuf)	(MMcuf)	(MMcuf)	(MMcuf)	(MMcuf)
December 31, 2015	49,524	25,457	74,981	216	73	289	1,432	637	2,069
Production	(9,569)	-	(9,569)	(18)	-	(18)	(1)	-	(1)
Technical revisions	6,835	(2,300)	4,535	(170)	(64)	(234)	(167)	(58)	(224)
Extensions and improved recovery	529	249	778	-	-	-	-	-	-
Acquisitions	19,565	7,932	27,498	54	14	68	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2016⁽²⁾	66,884	31,339	98,223	82	23	106	1,264	580	1,843

	Natural Gas Liquids			Total Oil Equivalent		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbbls)	(Mbbbls)	(Mbbbls)	(Mboe)	(Mboe)	(Mboe)
December 31, 2015	1,211	635	1,846	19,649	10,289	29,939
Production	(245)	-	(245)	(3,500)	-	(3,500)
Technical revisions	109	(88)	22	1,303	(1,762)	(459)
Extensions and improved recovery	30	16	46	288	110	398
Acquisitions	293	138	430	4,696	2,072	6,768
Dispositions	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2016⁽²⁾	1,399	701	2,099	22,437	10,709	33,145

(1) Excludes minor royalty interests attributable to certain working interest properties.

(2) Columns may not add due to rounding.

Working Interest Properties

The Corporation owns working interests in oil and natural gas properties. Production from these properties is comprised of approximately 68% oil and NGL and 32% natural gas. Working interest production averaged 2,283 boe per day in 2016, down from 2,635 boe per day in 2015. In 2016, 4 (0.3 net) wells were drilled, compared with 43 (7.4 net) wells during 2015.

In 2017, we expect to spend approximately \$6 million on development activities. Development plans are primarily oil related and are largely non-operated. Roughly one-third of our capital will be deployed in Southeast Saskatchewan (light oil) and the balance on the rest of our properties.

Year ended December 31, 2016		Southeast Saskatchewan ⁽³⁾⁽⁴⁾	Other ⁽³⁾⁽⁴⁾	Total ⁽³⁾⁽⁴⁾
Average working interest ⁽¹⁾	(%)	30.3	10.6	12.0
Wells drilled	(gross/net)	4/0.3	0/0	4/0.3
Operating income ⁽²⁾	(\$000s)	4,271	3,556	7,827
Average gross daily production	(boe/d)	758	1,525	2,283
Oil and NGL	(bbls/d)	662	880	1,542
Natural gas	(Mcf/d)	577	3,866	4,443
Net proved reserves	(Mboe)	416	2,535	2,950
Oil and NGL	(Mbbls)	374	1,509	1,883
Natural gas	(MMcf)	251	6,152	6,403
Net proved plus probable reserves	(Mboe)	888	4,247	5,135
Oil and NGL	(Mbbls)	795	2,632	3,428
Natural gas	(MMcf)	559	9,687	10,247
Future Net Revenue				
Discounted at 10% per year	(\$000s)	17,183	44,310	61,492
	(% of total)	28	72	100

(1) The percentage working interest share of reserves and production owned by Freehold in the properties before the deduction of royalties payable to others.

(2) Excludes income from interest and other.

(3) Excludes royalty interests.

(4) Includes non-unit and unit interests.

Southeast Saskatchewan

In the Southeast Saskatchewan area, we have title interests ranging from 10% to 100%, and working interests ranging from 2.5% to 100%. This region contains 33% of the working interest production and 17% of the net proved plus probable reserves associated with our working interest properties. Our average working interest is 30.3%, up from 23.6% in 2015. In 2016, we participated in 4 (0.3 net) wells, primarily on the Corporation's mineral title lands. Capital expenditures totalled approximately \$3 million in 2016 and in 2017 we have allocated about one-third of our capital budget to this area.

In aggregate, from 2005 to 2016, we have participated in 176 (62.9 net) wells in Southeast Saskatchewan. Of these, 84 (32.2 net) were Bakken formation wells and the balance were Mississippian – Frobisher/Alida targets. This participation is the result of the particularly favourable, oil based economics of these opportunities. Approximately 21,000 gross acres of the Corporation's Bakken mineral title lands are unleased.

Production decreased 22% in 2016 and was 87% oil and NGL and 13% gas. All of the oil production is of light and medium quality crude.

The majority of the Corporation's production from the Bakken in Southeast Saskatchewan is processed through facilities where Freehold pays processing fees. The Frobisher/Alida production in Southeast Saskatchewan is processed at non-operated facilities where Freehold has equity facility ownership interests ranging from 20% to 50%.

Other Working Interest Properties

We own various working interests in other properties, which accounted for 67% of the working interest production during 2016 and 83% of the net proved plus probable reserves associated with our working interest properties. Individually, each of these properties contributed less than 500 boe/d to production.

Capital expenditures totalled approximately \$2 million in 2016.

Production decreased 8% in 2016 and was 58% oil and NGL and 42% natural gas.

In 2017, we have allocated approximately two-thirds of our capital budget to these other working interest properties.

Working Interest Wells

The following table sets forth the number and status of wells as at December 31, 2016 in which we have a working interest that are producing or considered capable of production:

Property	Producing ⁽¹⁾				Non-Producing ⁽¹⁾⁽²⁾⁽³⁾			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Southeast Saskatchewan	169	47.6	-	-	97	18.3	-	-
Other	600	77.8	489	62.0	330	61.6	198	29.8
Total ⁽⁴⁾	769	125.5	489	62.0	427	79.9	198	29.8

(1) Based on public records.

(2) "Non-producing" wells means wells that are not producing but which are considered capable of production. Non-producing wells in which Freehold has an interest are located no further than ten kilometres from gathering systems, pipeline or other means of transportation.

(3) Not all wells owned by Freehold have been assigned reserves in the Trimble Report.

(4) Columns may not add due to rounding.

Development Activities

The following table sets forth the development wells in which we participated in during the years ended December 31, 2016 and December 31, 2015.

Years Ended December 31	2016		2015	
	Gross	Net	Gross	Net
Wells Drilled				
Oil wells	4	0.3	39	7.3
Natural gas wells	-	-	4	0.2
Service/other wells	-	-	-	-
Dry and abandoned wells	-	-	-	-
Total	4	0.3	43	7.5
Success rate	100%		100%	

Reconciliation of Working Interest Property Reserves⁽¹⁾

The following tables provide a summary of the changes in the gross oil and natural gas reserves on our working interest properties during 2016, based on forecast prices and costs:

	Light and Medium Crude Oil			Tight Oil			Heavy Crude Oil		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2015	1,435	1,316	2,751	145	204	349	651	722	1,373
Production	(277)	-	(277)	(132)	-	(132)	(149)	-	(149)
Technical revisions	138	(242)	(104)	202	97	298	(112)	(392)	(504)
Extensions and improved recovery	49	20	69	24	9	33	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	(2)	(2)
Economic factors	(50)	(21)	(71)	(7)	(7)	(13)	(9)	(5)	(14)
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2016⁽²⁾	1,296	1,072	2,368	232	303	534	381	323	704

	Conventional Natural Gas			Coal Bed Methane			Shale Gas		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2015	7,985	5,751	13,736	-	-	-	101	66	167
Production	(1,058)	-	(1,058)	(307)	-	(307)	-	-	-
Technical revisions	(2,126)	(2,867)	(4,993)	2,867	1,415	4,282	-	-	-
Extensions and improved recovery	165	58	223	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(83)	(62)	(145)	-	-	-	-	-	-
Economic factors	(177)	45	(131)	(230)	(95)	(325)	-	(3)	(3)
Infill drilling	-	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
December 31, 2016⁽²⁾	4,706	2,926	7,632	2,330	1,320	3,650	101	63	164

	Natural Gas Liquids			Total Oil Equivalent		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2015	207	157	364	3,786	3,368	7,154
Production	(66)	-	(66)	(851)	-	(851)
Technical revisions	87	(7)	80	438	(786)	(348)
Extensions and improved recovery	9	4	13	110	42	152
Acquisitions	-	-	-	-	-	-
Dispositions	(2)	(1)	(3)	(15)	(14)	(29)
Economic factors	(5)	-	(5)	(138)	(42)	(180)
Infill drilling	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
December 31, 2016⁽²⁾	230	153	383	3,329	2,569	5,897

(1) The working interest properties include certain minor royalty interests; however, the above table does not reflect such royalty interests because the reconciliation is presented on a gross basis.

(2) Columns may not add due to rounding.

OTHER OIL AND GAS INFORMATION

Oil and Natural Gas Wells

The following tables set forth, by province, the number and status of wells in which the Corporation has an interest as at December 31, 2016:

Working Interest Properties	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	568	64.5	289	43.2	481	59.6	188	27.9
Saskatchewan	188	60.1	125	36.1	-	-	1	0.4
British Columbia	4	0.2	10	0.3	8	2.4	9	1.5
Manitoba	9	0.7	3	0.2	-	-	-	-
Total ⁽¹⁾	769	125.5	427	79.9	489	62.0	198	29.8

(1) Columns may not add due to rounding.

Royalty Lands ⁽¹⁾	Non-Unitized		Unitized	
	Natural Gas Wells	Oil Wells	Natural Gas Wells	Oil Wells
Alberta	7,891	4,264	10,029	5,621
Saskatchewan	1,550	4,549	138	5,395
British Columbia	238	28	2	23
Manitoba	-	113	8	11
Ontario	145	-	-	-
Total	9,824	8,954	10,177	11,050

(1) Gross wells in which the Corporation has a royalty interest.

Properties with No Attributable Reserves

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

	Undeveloped Acres		
	Royalty Lands	Working Interest Lands	
	Gross	Gross	Net
Alberta	602,359	34,626	7,801
Saskatchewan	294,660	8,859	4,846
British Columbia	26,685	3,233	96
Manitoba	11,158	206	9
Ontario	21,102	-	-
Total	955,964 ⁽¹⁾	46,924	12,752

(1) Additional undeveloped royalty acres will exist within approximately 2,500,000 gross acres of royalty and mineral title lands acquired pursuant to the Husky Acquisition and therefore has not been categorized by province as of yet. This undeveloped acreage is undetermined at time of reporting pending release from Freehold's integration process.

There are no material work commitments on the undeveloped land holdings.

The area of unproved properties for which the Corporation expects its rights to explore, develop, and exploit to expire within the next year, are approximately 14,052 gross acres.

Undeveloped lands are calculated by adding the surface area acreage covered by the leases or agreements or portions of the leases or agreements without producing or potentially producing wells. In certain limited circumstances where we have rights in different formations under the same surface area pursuant to different leases or agreements, we have included the acreage with respect to all such leases or agreements. There are no significant factors or uncertainties associated with the undeveloped land.

Tax Horizon

The corporate income tax rate applicable to 2016 was approximately 27% (2015 – 26%) and the rate for 2017 and future years is currently 27%. Taxable income as a corporation is based on total income and expenses (which will vary depending on commodity prices, production volumes, and costs), reduced by claims for both accumulated tax pools and tax pools associated with current year expenditures. The Corporation's 2016 tax situation was affected by the corporate acquisition that occurred on January 23, 2015 which included approximately \$220 million of tax pools. Therefore, Freehold had no current taxes in 2016. In the current commodity price environment, the period for which we expect there to be no current income taxes is estimated to be beyond five years. As at December 31, 2016, Freehold's tax pools were \$1,028 million (additional information is provided in Freehold's December 31, 2016 management's discussion and analysis) which is available on SEDAR at www.sedar.com.

Capital Expenditures

Future capital expenditures are anticipated to be of the types that are intended to maintain or improve production. Freehold may finance capital expenditures from additional issuances of Common Shares, borrowings, farmouts or with working capital.

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2016. The acquisition costs were for Royalty Lands. The development costs were mostly on our working interest or leased mineral title lands.

	(\$000s)
Property acquisition costs ⁽¹⁾	
Proved properties	144,610
Undeveloped/unproved properties	17,980
Exploration costs	1
Development costs	5,217
Total	167,808

(1) As classified at the time of the acquisition.

Production Estimates

The following table sets out the volume of gross and net production estimated for the year ended December 31, 2017 in the Trimble Report, based on the forecast price case reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data". No field accounts for more than 20% of the production estimate.

Reserves Category	Light & Medium Crude Oil		Tight Oil		Heavy Crude Oil	
	Gross ⁽¹⁾ (bbls/d)	Net ⁽¹⁾ (bbls/d)	Gross ⁽¹⁾ (bbls/d)	Net ⁽¹⁾ (bbls/d)	Gross ⁽¹⁾ (bbls/d)	Net ⁽¹⁾ (bbls/d)
Proved						
Developed producing	497	2,309	221	454	261	1,672
Developed non-producing	1	1	107	83	-	3
Undeveloped	-	74	-	29	-	-
Total proved	498	2,384	328	565	261	1,675
Probable	151	291	64	64	71	119
Total proved plus probable ⁽²⁾	649	2,675	392	629	332	1,794

Reserves Category	Conventional Natural Gas		Coal Bed Methane		Shale Gas	
	Gross ⁽¹⁾ (Mcf/d)	Net ⁽¹⁾ (Mcf/d)	Gross ⁽¹⁾ (mMcf/d)	Net ⁽¹⁾ (Mcf/d)	Gross ⁽¹⁾ (Mcf/d)	Net ⁽¹⁾ (Mcf/d)
Proved						
Developed producing	2,145	25,609	735	709	-	5
Developed non-producing	114	89	-	-	-	-
Undeveloped	-	227	-	-	-	135
Total proved	2,259	25,925	735	709	-	140
Probable	346	811	23	22	-	7
Total proved plus probable ⁽²⁾	2,605	26,736	758	731	-	148

Reserves Category	Natural Gas Liquids		Total Oil Equivalent	
	Gross ⁽¹⁾ (bbls/d)	Net ⁽¹⁾ (bbls/d)	Gross ⁽¹⁾ (boe/d)	Net ⁽¹⁾ (boe/d)
Proved				
Developed producing	131	640	1,590	9,462
Developed non-producing	17	14	145	115
Undeveloped	-	12	-	175
Total proved	149	666	1,734	9,752
Probable	20	33	367	646
Total proved plus probable ⁽²⁾	168	699	2,102	10,399

(1) Under NI 51-101, gross production includes only working interests before the deduction of royalties payable and does not include royalties receivable. Net production is comprised of working interests minus royalties payable plus royalties receivable. The majority of the Corporation's assets are royalty interests. This causes our gross production to be lower than our net production and may hinder an investor's ability to compare our production with others in our industry.

(2) Columns may not add due to rounding.

Production History

The following table summarizes our production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	2016 Quarter Ended				2015 Quarter Ended			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Average daily production ⁽¹⁾								
Light and Medium Crude Oil ⁽²⁾ (bbls/d)	4,128	4,146	4,341	4,561	4,167	4,322	3,877	3,432
Heavy Crude Oil (bbls/d)	1,962	1,866	2,055	2,185	2,705	2,265	1,896	2,024
Conventional Natural Gas ⁽³⁾ (Mcf/d)	33,561	32,914	29,427	26,572	25,556	25,100	25,704	24,119
NGL (bbls/d)	895	783	740	799	683	496	560	583
Combined (boe/d)	12,579	12,281	12,041	11,974	11,815	11,266	10,617	10,058
Average price realized								
Light and Medium Crude Oil ⁽²⁾ (\$/bbl)	55.97	48.25	49.80	35.05	47.58	50.81	61.84	46.15
Heavy Crude Oil (\$/bbl)	38.63	36.39	36.61	19.68	32.84	38.35	50.97	35.64
Conventional Natural Gas ⁽³⁾ (\$/Mcf)	2.48	1.97	1.09	1.56	2.13	2.51	2.18	2.30
NGL (\$/bbl)	38.10	24.95	26.49	27.38	24.72	29.73	31.62	23.43
Combined (\$/boe)	33.72	28.69	28.48	22.23	30.34	34.11	38.63	29.80
Royalty expense ⁽⁴⁾								
Light and Medium Crude Oil ⁽²⁾ (\$/bbl)	0.66	0.56	0.31	0.33	0.26	0.97	1.54	1.59
Heavy Crude Oil (\$/bbl)	0.76	0.54	0.81	0.16	(0.21)	1.08	1.15	0.81
Conventional Natural Gas ⁽³⁾ (\$/Mcf)	0.01	(0.02)	-	0.03	0.01	0.02	0.01	0.03
NGL (\$/bbl)	0.53	0.38	0.46	0.21	0.64	0.60	0.26	0.38
Combined (\$/boe)	0.39	0.25	0.29	0.24	0.10	0.66	0.81	0.80
Operating expenses (\$/boe) ⁽⁵⁾								
Light and Medium Crude Oil ⁽²⁾ (\$/bbl)	7.78	6.70	5.81	5.73	7.02	5.51	6.89	6.12
Heavy Crude Oil (\$/bbl)	5.41	6.39	3.47	5.94	5.04	7.78	6.49	9.22
Conventional Natural Gas ⁽³⁾ (\$/Mcf)	0.27	0.19	0.28	0.27	0.20	0.35	0.34	0.32
NGL (\$/bbl)	2.12	2.30	3.12	2.22	1.95	3.57	2.87	2.63
Combined (\$/boe)	4.28	3.90	3.55	4.02	4.18	4.62	4.65	4.85
Netback received ⁽⁶⁾⁽⁷⁾								
Light and Medium Crude Oil ⁽²⁾ (\$/bbl)	47.53	40.99	43.68	28.99	40.30	44.33	53.41	38.44
Heavy Crude Oil (\$/bbl)	32.46	29.46	32.33	13.58	28.01	29.49	43.33	25.61
Conventional Natural Gas ⁽³⁾ (\$/Mcf)	2.20	1.80	0.81	1.26	1.92	2.14	1.83	1.95
NGL (\$/bbl)	35.45	22.27	22.91	24.95	22.13	25.56	28.49	20.42
Combined (\$/boe)	29.05	24.54	24.64	17.97	26.06	28.83	33.17	24.15

(1) Calculated by adding net production from our Royalty Lands and gross production from our working interest properties (except certain royalty interests owned by Freehold associated with the working interest properties have been deducted from the gross production of the working interest properties as such production is reflected in the net production from the Royalty Lands in the above table).

(2) Includes an immaterial amount of production from tight oil reserves.

(3) Includes an immaterial amount of production from coal bed methane and shale gas reserves.

(4) Royalty expense includes all Crown charges and royalty payments to third parties.

(5) Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas and natural gas liquids production. Overhead recoveries associated with operated properties were excluded from operating costs and accounted for as a reduction to general and administrative costs.

(6) Netbacks are calculated by subtracting royalty expenses and operating costs from revenues.

(7) Excludes income from potash, interest and other.

The following table summarizes our average daily production from important regions or fields for the year ended December 31, 2016:

	Light and Medium Crude Oil ⁽³⁾ (bbls/d)	Heavy Crude Oil (bbls/d)	Conventional Natural Gas ⁽⁴⁾ (Mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (boe/d)
Royalty Lands ⁽¹⁾					
Alberta West	903	90	23,064	541	5,377
Lloydminster	601	1,510	1,504	12	2,374
Saskatchewan East	1,849	1	1,621	64	2,185
Working Interest Properties ⁽²⁾					
Southeast Saskatchewan	586	-	577	76	758
Other	354	415	3,866	111	1,525
Total	4,293	2,016	30,632	804	12,219

(1) Production from the Royalty Lands is presented on a net basis.

(2) Production from our working interest properties is presented on a gross basis (except certain royalty interests owned by Freehold associated with the working interest properties have been deducted from the gross production as such production is reflected in the net production from the Royalty Lands in the above table).

(3) Includes an immaterial amount of production from tight oil reserves.

(4) Includes an immaterial amount of production from coal bed methane and shale gas reserves.

Environmental Obligations

Freehold is primarily a royalty company and has no employees. Most of the oil and gas properties in which Freehold has royalty interests are operated by other companies, and Freehold has little power to influence the operations of those properties. While environment, health and safety, and other risks arising out of these operations are not typically direct risks for Freehold, our business model is dependent on the industry operating in a responsible manner.

Approximately 80% of Freehold's royalty revenue comes from 30 oil and gas companies. Many of these companies are large Canadian producers that are members of the Canadian Association of Petroleum Producers ("CAPP") and align their operations with industry best practices. Operating members of CAPP are required to participate in CAPP's Responsible Canadian Energy™ program. The program represents a collective commitment to measure industry performance and to encourage members to find new approaches to reduce their environmental footprint, to ensure every worker returns home safely every day, and to continue to improve the ways we communicate and engage the public and other stakeholders.

Additional Information Concerning Abandonment and Reclamation Costs

We are liable for our share of ongoing environmental obligations and for the ultimate reclamation of our working interest properties upon abandonment. We have no reclamation responsibilities with respect to our Royalty Lands as these are the responsibility of the working interest owners. Ongoing environmental obligations are funded from operations.

For the purposes of estimating Reserves Data, abandonment and reclamation costs for all wells (both existing and undrilled wells) that have been attributed reserves have been taken into account. No allowance was made, however, for the abandonment and reclamation of any pipelines or facilities or for wells with no attributed reserves.

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

Additional information related to our estimated share of future environmental and reclamation obligations for the working interest properties (including all abandonment and reclamation costs associated with all existing wells, facilities, pipelines and leases) can be found in Freehold's consolidated financial statements for the year ended

December 31, 2016 and the accompanying management's discussion and analysis, which are available on SEDAR at www.sedar.com.

BORROWINGS

Freehold's credit facilities consist of a \$245 million extendible revolving term credit facility and a \$15 million extendible revolving operating facility, each available to the Corporation, FHT and/or the Partnership. Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees based on our debt to cash flow ratio (as defined therein). The facilities do not contain any financial covenants. The facilities are secured with \$400 million demand debentures over Freehold's petroleum and natural gas assets.

Freehold's borrowing base is dependent on our lenders' annual review and interpretation of our reserves and future commodity prices. Our borrowing base is currently set at \$260 million, but is reviewed on an annual basis in or prior to May of each year. The lenders at any time can request a redetermination of the borrowing base, which may require a repayment to the lenders within 90 days of receiving notice, of an amount that the indebtedness is in excess of the redetermined borrowing base.

Under our credit facilities, we are restricted from paying dividends if we are or would be in default under the facilities or if our borrowings thereunder exceed our borrowing base. As at December 31, 2016, Freehold was in compliance with all of the covenants under its credit agreement.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas, including the governments of Canada, Alberta, British Columbia, Saskatchewan, and Manitoba, all of which investors in the oil and gas industry should carefully consider. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future. The following comprises some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

In Canada, producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, regional market and transportation issues also influence prices. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (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 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 VI (Oil and Gas) Regulations* came into effect on July 31, 2015 and provides the requirements for obtaining long-term licences.

Natural Gas

Canada's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and

the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange, Intercontinental Exchange or the New York Mercantile Exchange in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³ 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 requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

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

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. 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 gas industry is uncertain.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are carved out of the working interest owner's interest, from time to time, through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

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

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

Alberta

In Alberta, the Crown owns 81% of the province's mineral rights. The remaining 19% are 'freehold' mineral rights owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies. Provincial government royalty rates apply to Crown-owned mineral rights. On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**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 "New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) (the "**Alberta 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 total depth, length, and proppant placed). 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. Depending on the commodity price of the substance the well is producing, the royalty rate could range from 5% - 40%. The metrics for calculating the Mid-Life phase royalty are based on commodity prices and are intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the Mature phase of the MRF, once a well reaches the tail end of its cycle and production falls below a Maturity Threshold, currently the equivalent of 194 m³ per month (40 barrels of oil equivalent per day or 345,500 m³ of gas per month), the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the Mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well.

On July 11, 2016, the Government of Alberta released details of the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs, that came into effect on January 1, 2017, are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources in an effort to make difficult investments economically viable and to increase royalties. Certain eligibility criteria must be satisfied in order for a proposed project to fall under each program. Enhanced recovery scheme applications can be submitted to the Alberta Energy Regulator ("**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. 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 Alberta Royalty Framework until January 1, 2027. Royalty rates for conventional oil are set by a single sliding scale formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime depends on the price of each of the components of the gas stream, the productivity of the well, its acid gas factor and the depth of the producing zone. These factors are employed on a sliding scale formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36% and a minimum royalty rate of 5%.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from lands where the Crown does not hold the rights to mines and minerals and is derived from the *Freehold Mineral*

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

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") 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 ten-year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is classified as either "old oil" which is produced from a pool discovered before October 31, 1975, "new oil" produced from a pool discovered between October 31, 1975 and June 1, 1998, and "third-tier oil" produced from a pool discovered after June 1, 1998 or through an enhanced oil recovery ("**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 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%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to \$4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale depending on the total number of hectares owned by the entity.

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 3 year royalty holiday or 283,000,000 m³ 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 m³ 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 m³ 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 m³;
- *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 m³ per metre of depth for exploratory wildcat wells and less than 11 m³ 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 m³. 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 be exempt from the payment of a royalty for the first 36 months of production or 11,450 m³ 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 gas rights. For the Crown lands, taxes (the "**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. In addition, a mineral rights tax is charged to owners of mineral rights paid on an annual basis at the rate of \$1.50 per acre owned.

The amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into types, being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil, being "fourth tier oil", "third tier oil", "new oil" and "old oil", depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently:

- Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as third tier oil or fourth tier oil).
- Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002.
- For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood

projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the Production Tax Factor ("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 a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the 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.

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 per 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 wellhead 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 EOR 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 from 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 licences and applications in the oil and gas sector by eliminating 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 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 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 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 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 m³. 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 m³;
 - Deep exploratory wells drilled below the Birdbear formation earn a HOV of 8,000 m³; and
 - Deep development wells completed for production in the Birdbear formation or deeper earn a HOV of 8,000 m³;

- *Horizontal Well Incentive* provides a HOV of 8,000 m³ 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 m³ 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 m³ 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 m³ 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 oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia, Saskatchewan, and Manitoba have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. The Government of 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 issued after January 1, 2009 at the conclusion of the primary term of the lease or licence.

Production and Operation Regulations

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

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which is subject to governmental review and revision

from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("GHG") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

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

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

On June 20, 2016, the Federal Government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the 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. The Federal Government has not provided any indication on what changes—if any—will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

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

Alberta

The AER is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System ("IRMS"). The IRMS method to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities, by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the 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 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

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.

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

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

Phase 1 Consultation of the North Saskatchewan Region Plan ("**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 and affects activities in central Alberta, and encompasses an area between the province's borders with British Columbia and Saskatchewan. The Upper Peace Region Plan, Lower Peace Region Plan, Red Deer Region Plan and Upper Athabasca Region Plan have not been started.

British Columbia

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*, in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Saskatchewan

In May 2011, the Government of 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, the Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Manitoba

In Manitoba, the Petroleum Branch of 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**"), *The Oil and Gas Production Tax Act* and related regulations and guidelines.

Liability Management Rating Programs

Alberta

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. Alberta's *Oil and Gas Conservation Act* ("**OGCA**") establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct or is unable to meet its obligations. The Orphan 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 Fund posed by unfunded liability of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with

a security deposit. The ratio of deemed 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.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "**Changes**") 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 Appeal of Alberta. In *Redwater Energy Corporation (Re)*, 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the 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 licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licences* as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licensee 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 licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.
3. As a condition of transferring existing 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. In the short term the interim measures caused delays in completing transactions and reduced the pool of possible purchasers, however, transactions have been approved following a more rigorous review by the 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 noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota.

British Columbia

In British Columbia, the Commission oversees the Liability Management Rating Program (the "**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 LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

Saskatchewan

In Saskatchewan, the Ministry of the Economy administers the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets 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 licence transfer applications as non-routine until further notice.

Manitoba

To date, the Government of 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.

Climate Change Regulation

Federal

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

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (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 Government of Canada 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 Government of Canada 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 Government of Canada 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 Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of \$10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by \$10 annually until it reaches \$50 per tonne in 2022 at which time the program will be reviewed.

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

Alberta

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 of 2018. All fuel consumption—including gasoline and natural gas—will be subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Regulated Emitters will remain subject to the *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

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.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The *MRGGA* 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.

Manitoba

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

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation'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 Corporation's business and the oil and natural gas business generally.

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 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. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in the case of Alberta, at the provincial level, and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that have been announced or that may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional downward pressure on oil and 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 Corporation's reserves, rendering certain reserves uneconomic. In addition, lower commodity prices have restricted, and are anticipated to continue to restrict, the Corporation's and its partners' and royalty payors' cash flow resulting in reduced capital expenditure budgets. As a result, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds or if it is able to do so, it may be on unfavourable and highly dilutive terms.

Prices, Markets and Marketing

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

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. 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 and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's and its partners' and royalty payors' ability to access such markets. Oil prices are expected to remain volatile as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, and non-OPEC member countries' decisions on production levels, among other factors. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation and its partners and royalty payors might also elect not to produce from certain wells at lower prices.

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

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

Reliance on Royalty Payors

The Corporation relies on other companies drilling and producing from lands in which the Corporation has a royalty interest. The Corporation has very limited ability to exercise influence over the decision of companies to drill and produce from lands in which the Corporation has a royalty interest. The Corporation's return on lands on which it has a royalty interest depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the capital expenditure budgets and financial resources of the companies which have a working interest in such lands, the operator's ability to efficiently produce the resources from such lands and commodity prices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may have a working interest in the lands in which the Corporation has a royalty interest, may be in financial difficulty, which could affect their ability to fund and pursue capital expenditures on such lands. In addition, weak commodity prices might 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 Corporation has a royalty interest will negatively affect the Corporation's cash flows and financial results.

Any financial difficulty of companies which have assets in which the Corporation has a royalty interest may affect the Corporation'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 or insolvency. In addition, to the extent any companies who have assets in which the Corporation has a royalty interest go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency it is possible that the Corporation's royalty interest may not be (or may not be recognized as) an interest in land and as such the Corporation's royalty interest may not survive such bankruptcy or insolvency proceedings.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual or other obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Take-in-Kind

All agreements that the Corporation has entered into that create a new royalty stipulate that the royalty interest so acquired by the corporation is an interest in land and as such is separate and distinct from the interest of the royalty payor. In addition, all of these new royalty agreements provide the Corporation with the right, but not the obligation, to take its share of production in kind rather than have the royalty payor sell the Corporation's royalty production on behalf of the Corporation as agent for the Corporation. These provisions serve to mitigate the counter party risk attributable to any financial difficulty of the royalty payors under these agreements. The previously discussed provisions may not exist in certain of the royalty agreements previously entered into by other royalty recipients who subsequently sold their respective interest as a royalty recipient to the Corporation.

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 Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation and its partners and royalty payors to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that the Corporation or its partners and royalty payors will discover or acquire further commercial quantities of oil and natural gas.

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

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

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

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

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

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has a working interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations the Corporation may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators or recovering amounts owing to the Corporation from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on the Corporation's financial and operational results.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation'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 of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the common shares of the Corporation will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, may realize less than their carrying value on the financial statements of the Corporation.

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 the North American Free Trade Agreement, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including the Corporation.

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 taking 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 and its partners' and royalty payors' ability to market its products internationally, increase costs for goods and services required for the Corporation's and its partners' and royalty payors' operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of the Common Shares.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing and waterfloods, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that it produces effectively.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation and its partners and royalty payors delivers its products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that the Corporation and its partners and royalty payors can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in the Corporation's and its partners' and royalty payors' inability to realize the full economic potential of its production or in a reduction of the

price offered for the Corporation's and its partners' and royalty payors' production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's and its partners' and royalty payors' production, operations and financial results. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change, or uncertainty, in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, operations and cash flows. In addition, the federal government has signaled 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-Mégantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail, imposed a per tonne levy of \$1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Corporation's ability to process its production and deliver the same for sale.

Reserve Estimates

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

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

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

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

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

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

Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. In particular, the Corporation competes with other companies for the acquisition of royalty interests in oil and gas properties. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation and who may have lower costs of, and better access to, capital. The Corporation's ability to increase its reserves in the future will depend partially on its and its partners' and royalty payors' ability to explore and develop its present properties, but will primarily depend on its ability to acquire royalty interests in suitable producing properties or properties with future reserve or resource potential. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage.

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

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

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's and its partners' and royalty payors' costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation and its partners' and royalty payors' will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation and its partners' and royalty payors' will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect the Corporation's business, financial condition and the market value of its Common Shares or its assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity.

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 Corporation's or its partners' or royalty payors' projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's or its partners' or royalty payors' operations, 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*".

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water and sand additives (or such other fluids and materials as may be used from time to time) under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's and its partners' and royalty payors' costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation and its partners and royalty payors are ultimately able to produce from its reserves.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production,

development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Liability Management

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 obligations. 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 the Corporation's 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. In addition, the liability management system may prevent or interfere with the Corporation's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The recent Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re)* 2016 ABQB 278, found an operational conflict between the *Bankruptcy and Insolvency Act* 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*".

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it would seek a 17% reduction in GHG emissions from 2005 levels by 2020; however, these GHG emission reduction targets were not binding. As a result of the UNFCCC adopting the Paris Agreement on December 12, 2015, which Canada ratified on October 3, 2016, the Government of Canada implemented new GHG emission reduction targets of a 30% reduction from 2005 levels by 2030. In addition, the Government of Canada announced it would implement a Canada wide price on carbon to further reduce its GHG emissions. In addition, 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. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "*Industry Conditions - Climate Change Regulation*".

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, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of the Corporation's reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price the Corporation receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Corporation's operations, which may have a negative impact on the Corporation's financial results.

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

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the common shares of the Corporation.

Substantial Capital Requirements

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

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

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and gas industry and/or global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

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

Credit Facility Arrangements

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with non-financial covenants under its credit facility and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. In addition, the Corporation's credit facility may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014. There remains a substantial amount of uncertainty as to when and if commodity prices will recover. Depressed commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

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

Issuance of Debt

From time to time, the Corporation may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

Although the Corporation has never hedged, from time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's 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;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

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

Availability of Drilling Equipment and Access

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

Diluent Supply

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

Insurance

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

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

Dilution

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

Management of Growth

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The

inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

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

Dividends

The amount of future cash dividends paid by the Corporation, if any, will be subject to the discretion of the Board of Directors of the Corporation and may vary depending on a variety of factors and conditions existing from time to time, including funds from operations, fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements and debt levels, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of the Corporation, the dividend policy of the Corporation from time to time and, as a result, future cash dividends could be reduced or suspended entirely.

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

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, the ability of the Corporation to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that the Corporation is required to use funds from operations to finance capital expenditures or property acquisitions, the cash available for dividends may be reduced.

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation, and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Corporation's financial condition.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Corporation's business and financial results.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation'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 Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

The Corporation files all required income tax returns and believes that it is 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 Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and 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 Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Seasonality

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

Information Technology Systems and Cyber-Security

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

Further, the Corporation 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 Corporation'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 our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. The Corporation applies technical and process controls in line with industry-accepted standards to protect our information assets and systems; however, these controls may not adequately prevent cyber-security breaches. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Conflicts of Interest

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the 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 Corporation to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "*Conflicts of Interest*".

Reliance on Key Personnel

The Corporation'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 Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on acquiring and managing oil and gas royalties and developing and producing its working interest oil and gas assets in the Western Canada Sedimentary Basin. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown 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 information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

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

DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of Freehold consists of an unlimited number of Common Shares and 10,000,000 Preferred Shares. As of the date hereof, there are 117,962,667 Common Shares and no Preferred Shares 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

Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Freehold. Subject to the prior satisfaction of all preferential rights attached to other classes of shares of Freehold, the holders of Common Shares are entitled to receive dividends if, as and when declared by the Board of Directors and to receive pro rata the remaining property and assets of Freehold upon its dissolution or winding-up.

Preferred Shares

The Preferred Shares are issuable in one or more series and the Board of Directors may fix their issue, the number of shares of each series and the designation, rights, privileges, restrictions and conditions attached to each series of Preferred Shares. The Preferred Shares of each series shall, with respect to the payment of dividends and the distribution of assets or the return of capital in the event of the liquidation, dissolution or winding-up of Freehold, rank on a parity with the Preferred Shares of every other series and are entitled to a preference over the Common Shares and any other shares of Freehold ranking junior to the Preferred Shares.

Other than in the case of a failure to declare or pay dividends specified in any series of the Preferred Share, the voting rights attached to the Preferred Shares shall be limited to one vote per Preferred Share at any meeting where the Preferred Shares, if any, and Common Shares vote together as a single class.

MARKET FOR SECURITIES

Common Shares

The Common Shares are listed and trade on the TSX under the symbol "FRU". The following table sets forth the high, low and closing trading prices and the aggregate trading volume of the Common Shares for the periods indicated:

TORONTO STOCK EXCHANGE COMMON SHARES TRADING RANGE

	(Cdn\$ per Common Share)			Volume Traded
	High	Low	Close	
2016				
January	11.25	8.29	10.71	9,304,210
February	10.80	9.25	10.69	4,703,355
March	12.05	10.12	10.54	5,682,086
April	13.00	9.66	12.52	8,248,688
May	12.50	11.01	11.59	8,684,494
June	12.55	11.01	11.91	6,625,863
July	12.20	11.05	11.14	3,513,068
August	12.02	10.61	11.29	8,463,548
September	13.09	10.95	12.65	8,896,882
October	13.46	12.55	12.60	4,346,828
November	13.47	11.68	13.34	5,425,311
December	15.16	13.47	14.17	5,667,505
2017				
January	14.38	12.74	12.92	5,578,582
February	13.80	12.22	13.61	4,607,575
March 1	13.94	13.49	13.74	633,768

PRIOR SALES

Other than Deferred Share Units, Freehold did not issue any securities of a class that is not listed or quoted on market place during the year ended December 31, 2016. The Corporation issued the following Deferred Share Units (including notional Deferred Share Units resulting from dividends) redeemable to acquire an equal number of Common Shares (less tax withholding) pursuant to the Deferred Share Unit Plan during the year ended December 31, 2016:

Date	Numbered Deferred Share Units	Deemed Price per Deferred Share Unit
January 1, 2016	41,437	\$10.86
January 15, 2016	1,363 ⁽¹⁾	\$9.09
February 15, 2016	1,266 ⁽¹⁾	\$10.07
March 15, 2016	1,205 ⁽¹⁾	\$10.66
April 15, 2016	678 ⁽¹⁾	\$10.89
May 15, 2016	660 ⁽¹⁾	\$11.24
May 19, 2016	5,226	\$11.48
June 15, 2016	670 ⁽¹⁾	\$11.41
July 15, 2016	647 ⁽¹⁾	\$11.86
August 15, 2016	654 ⁽¹⁾	\$11.77
September 15, 2016	703 ⁽¹⁾	\$11.00
October 15, 2016	509 ⁽¹⁾	\$13.12
November 15, 2016	558 ⁽¹⁾	\$12.01
December 15, 2016	478 ⁽¹⁾	\$14.10

(1) Issued as notional Deferred Share Units resulting from the payment of dividends of the Common Shares.

ESCROWED SECURITIES

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

DIVIDENDS

The payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. As at December 31, 2016, our legal stated capital was \$1.0 billion.

Monthly dividends of Freehold are currently declared for Shareholders of record as of the last day of each month and are paid on or about the 15th day of the following month. The dividends are "eligible dividends" for income tax purposes and thus qualify for the enhanced gross-up and tax credit regime available to certain holders of Common Shares. The amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, participation levels in the DRIP, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates, income taxes and the satisfaction of solvency tests imposed by the ABCA for the declaration and payment of dividends.

The Board of Directors reviews the dividend policy quarterly and at its discretion, any excess income available for dividends may be directed toward repayment of long-term debt and improvements in working capital.

Record of Cash Dividends

Since January 1, 2017, Freehold has declared a cash dividend of \$0.04 per Common Share for Shareholders of record on January 31, 2017, which was paid on February 15, 2017, has declared a cash dividend of \$0.04 per Common Share

for Shareholders of record on February 28, 2017, which is payable on March 15, 2017 and has declared a cash dividend of \$0.05 per Common Share for Shareholders of record on March 31, 2017, which is payable on April 17, 2017.

The tables below set forth the amount of cash dividends paid on the Common Shares during the three most recently completed financial years:

Record Date	Payment Date	Cdn\$ per Share
2014		
January 31, 2014	February 17, 2014	0.14
February 28, 2014	March 17, 2014	0.14
March 31, 2014	April 15, 2014	0.14
April 30, 2014	May 15, 2014	0.14
May 31, 2014	June 16, 2014	0.14
June 30, 2014	July 15, 2014	0.14
July 31, 2014	August 15, 2014	0.14
August 31, 2014	September 15, 2014	0.14
September 30, 2014	October 15, 2014	0.14
October 31, 2014	November 17, 2014	0.14
November 30, 2014	December 15, 2014	0.14
December 31, 2014	January 15, 2015	0.14
		1.68
2015		
January 31, 2015	February 17, 2015	0.09
February 28, 2015	March 16, 2015	0.09
March 31, 2015	April 15, 2015	0.09
April 30, 2015	May 15, 2015	0.09
May 31, 2015	June 15, 2015	0.09
June 30, 2015	July 15, 2015	0.09
July 31, 2015	August 17, 2015	0.09
August 31, 2015	September 15, 2015	0.09
September 30, 2015	October 15, 2015	0.07
October 31, 2015	November 16, 2015	0.07
November 30, 2015	December 15, 2015	0.07
December 31, 2015	January 15, 2016	0.07
		1.00
2016		
January 31, 2016	February 15, 2016	0.07
February 29, 2016	March 15, 2016	0.07
March 31, 2016	April 15, 2016	0.04
April 30, 2016	May 16, 2016	0.04
May 31, 2016	June 15, 2016	0.04
June 30, 2016	July 15, 2016	0.04
July 31, 2016	August 15, 2016	0.04
August 31, 2016	September 15, 2016	0.04
September 30, 2016	October 17, 2016	0.04
October 31, 2016	November 15, 2016	0.04
November 30, 2016	December 15, 2016	0.04
December 31, 2016	January 16, 2017	0.04
		0.54

Passive Foreign Investment Company

In consultation with its U.S. tax advisors, Freehold believes it should 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. Freehold, 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 Freehold.

Direct Deposit Plan

A direct deposit plan has been established for the Corporation to provide holders who have Canadian bank accounts with a method of receiving cash dividends as a direct deposit into their bank account.

Dividend Reinvestment Plan

The purpose of the DRIP is to provide Shareholders who are residents of Canada (within the meaning of the Tax Act) with a method of reinvesting cash dividends into new Common Shares. The DRIP allows for the issuance of Common Shares from treasury at a 5% discount to market (i.e. 95% of the weighted average closing price for the ten trading days preceding each payment date). Effective with the August 2016 dividend, Freehold suspended the DRIP until further notice. As a result, as of September 15, 2016, Shareholders that were enrolled in the DRIP received the regular monthly cash dividend.

U.S. Currency Payment Plan

The U.S. currency payment plan allows holders of Common Shares of the Corporation who maintain U.S. currency accounts to obtain payments in U.S. currency.

CORPORATE GOVERNANCE

General

Subject to the ultimate authority of the Board of Directors, Freehold, FHT and the Partnership are managed by the Manager.

Governance Agreement

The Governance Agreement provides that if the Manager and its affiliates, including the CN Pension Trust Funds, hold 10% or more of the issued and outstanding Common Shares, the Manager will have the right to nominate for election two individuals as directors of Freehold. If the Manager and its affiliates hold less than 10% of the issued and outstanding Common Shares, the Manager will have the right to nominate for election one individual as a director of Freehold. If the individuals nominated by the Manager fail to get elected or if the Manager ceases to hold any Common Shares (in which case the Manager will not have the right to nominate any individuals as directors of Freehold) but continues to act as manager of Freehold pursuant to the Management Agreement, the Governance Agreement will provide the Manager with the right to have an observer present at all meetings of directors of Freehold. The CN Pension Trust Funds holds, directly or indirectly, approximately 21.5% of the outstanding Common Shares and as a result, has the right to nominate two individuals as directors of Freehold.

Decision Making

Although the Manager provides certain advisory and management services to Freehold pursuant to the Management Agreement, the Board of Directors supervises the management of the business and affairs of Freehold. In particular, significant operational decisions and all decisions relating to: (a) issuances of additional securities of Freehold; (b) the acquisition and disposition of properties of Freehold, and its subsidiaries and partnerships for a purchase price or proceeds in excess of \$10 million; (c) capital expenditures outside of approved budgets; (d) establishment of credit facilities and hedging; and (e) the payment of dividends to Shareholders of Freehold, are made by the Board of Directors. Any amendment to the Management Agreement requires the approval of the Board of Directors. The Board of Directors hold regularly scheduled meetings to review the business and affairs of Freehold and make any necessary decisions relating thereto.

Board of Directors of Freehold

As at March 2, 2017, the Board of Directors was comprised of eight individuals. The name, province of residence, position held and principal occupation of each director of Freehold are as follows:

Name and Province of Residence	Position with Freehold	Principal Occupation	Director Since
Gary R. Bugeaud ⁽¹⁾⁽²⁾ Alberta, Canada	Director	Corporate Director	May 14, 2015
Peter T. Harrison ⁽⁴⁾ Quebec, Canada	Director	Manager, Oil and Gas Investments CN Investment Division	July 29, 1996 ⁽⁵⁾
J. Douglas Kay ⁽³⁾ Alberta, Canada	Director	Corporate Director	May 11, 2016
Arthur N. Korpach ⁽¹⁾⁽²⁾ Alberta, Canada	Director	Corporate Director	May 9, 2012
Susan M. MacKenzie ⁽²⁾⁽³⁾ Alberta, Canada	Director	Corporate Director	May 14, 2014
Thomas J. Mullane ⁽⁴⁾ Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer, Rife (private oil and gas exploration and production company)	May 15, 2013
Marvin Romanow Alberta, Canada	Chair of the Board	Corporate Director	May 14, 2015
Aidan M. Walsh ⁽¹⁾⁽³⁾ Alberta, Canada	Director	Chief Executive Officer of Baccalieu Energy Inc. (a private oil and gas exploration and production company)	May 15, 2013

(1) Member of Audit Committee.

(2) Member of Governance, Nominating and Compensation Committee.

(3) Member of Reserves Committee.

(4) Directors nominated for election at the last annual meeting of Shareholders held on May 11, 2016 by the Manager pursuant to the Governance Agreement.

(5) Reflects the date of election or appointment as a member of the board of directors of Freehold Resources Ltd. prior to completion of the plan of arrangement on January 1, 2011 that resulted in Freehold, directly or indirectly, acquiring all of the assets and assuming all of the liabilities of Freehold Royalty Trust.

Officers of Freehold

The following table sets forth the name, province of residence, position held and principal occupation of each of the officers of Freehold:

Name and Province of Residence	Position with Freehold	Principal Occupation	Officer Since
Thomas J. Mullane Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer of Rife	July 18, 2012
Darren G. Gunderson Alberta, Canada	Vice-President, Finance and Chief Financial Officer	Vice-President, Finance and Chief Financial Officer of Rife	November 13, 2003 ⁽¹⁾
David M. Spyker Alberta, Canada	Vice-President, Production	Vice-President, Production of Rife	November 28, 2016
Michael J. Stone Alberta, Canada	Vice-President, Land	Vice-President, Land of Rife	March 1, 2010 ⁽¹⁾
Michael J. Mogan Alberta, Canada	Controller	Controller of Freehold	August 13, 2008 ⁽¹⁾
Karen C. Taylor Alberta, Canada	Corporate Secretary	Corporate Secretary of Rife	February 27, 2008 ⁽¹⁾

(1) Reflects the date of appointment as an officer of Freehold Resources Ltd. prior to completion of the plan of arrangement on January 1, 2011 that resulted in Freehold, directly or indirectly, acquiring all of the assets and assuming all of the liabilities of Freehold Royalty Trust.

Each of the directors and officers of Freehold has been engaged in his or her principal occupation or in other capacities with the same firm or organization for the past five years except for Mr. Korpach, who prior to May 31, 2012 was Vice-Chairman, Investment Banking at CIBC World Markets Inc., Mr. Romanow, who prior to May 2012 was President and Chief Executive Officer of Nexen Inc., Mr. Mullane, who prior to joining Rife in July 2012 was Senior Vice President of Bonavista Energy Corporation, Mr. Bugeaud, who prior to his retirement in December 2013 was Managing Partner at Burnet, Duckworth and Palmer LLP., and Mr. Spyker, who prior to joining Rife in November 2016 was Chief Operating Officer at Anderson Energy Inc.

As at March 2, 2017, the directors and senior officers of Freehold, as a group, beneficially owned or controlled, directly or indirectly, 155,751 Common Shares or less than 1% of the issued and outstanding Common Shares. CN Pension Trust Funds, owned, directly or indirectly, 25,353,264 Common Shares (approximately 21.5%) of the Corporation as at March 2, 2017. From 1996 to March 2, 2017, the Manager has received 2,875,450 Common Shares in payment of the Management Fee.

The following is a brief description of the backgrounds of the directors and officers of Freehold.

Gary R. Bugeaud

Mr. Bugeaud is a Corporate Director. He retired (December 31, 2013) as Managing Partner of Burnet, Duckworth & Palmer LLP. He is a director of Raging River Exploration Inc., Trustee of Alberta Cancer Foundation and Member of the Dean's Advisory Committee of the College of Law of the University of Saskatchewan. He is a former corporate lawyer with over 23 years of legal experience focused on securities, corporate finance, mergers and acquisitions, and corporate governance matters. Mr. Bugeaud has a Bachelor of Commerce (Finance) degree and a Bachelor of Laws

degree from the University of Saskatchewan. Mr. Bugeaud holds the ICD.D designation from the Institute of Corporate Directors.

Peter T. Harrison

Mr. Harrison is Manager, Oil and Gas Investments of the CN Investment Division (Montreal), which manages one of the largest corporate pension funds in Canada. Prior to joining the CN Investment Division in August 2009, he was Senior Vice-President of Montrusco Bolton Investments Inc. (Montreal). He has a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario, and is a Chartered Financial Analyst.

J. Douglas Kay

Mr. Kay is a Corporate Director and an experienced oil and gas industry executive with strong land, finance, negotiating and leadership skills. He has over 38 years of diverse responsibilities with Canadian based oil and gas exploration and production companies. Mr. Kay holds a Bachelor of Economics degree from the University of Calgary, is a graduate of the Management Development Program of the University of Western Ontario, and holds the designation of P. Land through the Canadian Association of Petroleum Landmen (CAPL). He currently serves on the boards of Westbrick Energy Ltd. as Chairman, is a director and former Chair of the Explorers and Producers Association of Canada (EPAC) and a founder and Chairman of Trout River Energy Inc.

Arthur N. Korpach

Mr. Korpach is a corporate director and past Vice-Chairman Investment Banking at CIBC World Markets Inc. (Calgary). He is a Fellow Chartered Accountant and a Chartered Business Valuator with 27 years of investment banking experience and four years of public audit experience. He has a Bachelor of Commerce degree from the University of Saskatchewan and an MBA from Harvard Business School. Mr. Korpach is a director of Canexus Corporation and HPC Energy Services Limited. He is past Chair of the Board of the Heart and Stroke Foundation Alberta, past Chair of the board of directors of the United Way of Calgary and Area, past Chair of the Accounting Standards Board of the Canadian Institute of Chartered Accountants, and past director of Mount Royal University and its Foundation. Mr. Korpach holds the ICD.D designation from the Institute of Corporate Directors.

Susan M. MacKenzie

Ms. MacKenzie is a Corporate Director. She formerly served as Chief Operating Officer with Oilsands Quest Inc., as Vice-President of Human Resources and Vice-President of *In Situ* Development & Operations at Petro-Canada and held engineering and leadership roles in natural gas, conventional oil and heavy oil exploitation with Amoco Canada. Ms. MacKenzie holds a Bachelor of Engineering (Mechanical) degree from McGill University and an MBA from the University of Calgary. She is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA), and holds the ICD.D designation from the Institute of Corporate Directors. She is a director of Enerplus Corporation, FortisAlberta and TransGlobe Energy Corporation.

Thomas J. Mullane

Mr. Mullane is the President and Chief Executive Officer of the Corporation. He joined Rife as Executive Vice-President and Chief Operating Officer on July 18, 2012 and was appointed President and Chief Executive Officer on May 17, 2013. He has over 35 years of industry experience and a broad background in exploitation and production engineering gathered from both domestic and international assignments. Prior to joining Rife, Mr. Mullane most recently served as Senior Vice-President of Bonavista Energy Corporation. Over his 12 years at Bonavista, his responsibilities included acquisitions and divestitures, exploitation and reservoir engineering management. He graduated from the University of Alberta in 1983 with a Bachelor of Science degree in Chemical Engineering and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Marvin F. Romanow

Mr. Romanow is a Corporate Director, and since 2012, Executive in Residence at the University of Saskatchewan. Prior thereto he was the President and Chief Executive Officer of Nexen Inc. Mr. Romanow has over 30 years of experience in the oil and gas industry, and has held senior positions in engineering, operations, finance and

planning with Wascana Energy Inc., Amoco Canada Petroleum Company Ltd., and Dome Petroleum Ltd. Mr. Romanow is a graduate of Harvard's Program for Management Development and in October 2007 he completed INSEAD's Advance Management Programme. In April of 2007 he was awarded Canada's "CFO of the Year" award and in September of the same year he received the Petroleum Economist award for "Energy Executive of the Year 2008". He currently serves on the boards of SaskPower, Alberta Teacher's Retirement Fund, Alberta Petroleum Marketing Commission (Commissioner), Bank of Tokyo Mitsubishi Canada, and Arnie Charbonneau Cancer Institute.

Aidan M. Walsh

Mr. Walsh is Chief Executive Officer of Baccalieu Energy Inc. (Calgary), a private junior oil and gas company that he co-founded in 2008. He was President and Chief Executive Officer of Burmis Energy Inc. from 2003 to 2008, and President and Chief Executive Officer of Elk Point Resources Inc. from 1993 to 2003. He is currently a director and former Chair of the Explorers and Producers Association of Canada (EPAC). Mr. Walsh has a Bachelor of Engineering degree in Mechanical Engineering from Memorial University of Newfoundland and a Masters of Business Administration degree from the University of Calgary. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Mr. Walsh holds the ICD.D designation from the Institute of Corporate Directors.

Darren G. Gunderson

Mr. Gunderson is Vice-President, Finance and Chief Financial Officer of the Corporation and was appointed Vice-President, Finance and Chief Financial Officer of Freehold Resources Ltd. and Rife on August 13, 2008. He joined Rife in 1991 in the accounting department and became Controller in 1999. Mr. Gunderson has a Bachelor of Commerce degree from the University of Saskatchewan and is a Certified Public Accountant (CPA, CGA).

David M. Spyker

Mr. Spyker was appointed Vice-President, Production of the Corporation and Rife effective November 28, 2016. Prior to joining Rife, Mr. Spyker held various roles at Anderson Exploration Ltd., Anderson Energy Ltd., and Anderson Energy Inc. with the past 8 years in the role of Chief Operating Officer. Mr. Spyker holds a Bachelor of Sciences degree in Mechanical Engineering from the University of Alberta and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Michael J. Stone

Mr. Stone is Vice-President, Land of the Corporation and Rife and has held such position since March 1, 2010. Mr. Stone joined Rife in January 2009 as Manager, Land Negotiations and Business Development. Prior to joining Rife, Mr. Stone was Vice-President, Land with Real Resources Ltd. Mr. Stone has a Bachelor of Commerce degree from the University of Calgary and is a member of the Canadian Association of Petroleum Landmen (CAPL).

Michael J. Mogan

Mr. Mogan, Controller of the Corporation, was appointed Controller of Freehold Resources Ltd. effective August 13, 2008. Mr. Mogan joined Rife in 2003 as Senior Accountant and was the Manager, Financial Accounting prior to his current role. He is a Certified Public Accountant (CPA, CMA).

Karen C. Taylor

Ms. Taylor, Corporate Secretary of the Corporation, joined Rife in February 1997 as Manager, Corporate Communications and held the position of Manager, Investor Relations from January 1999 to August 2013. Her appointment as Corporate Secretary of Freehold Resources Ltd. and Rife was effective February 27, 2008. Ms. Taylor is a member of the Governance Professionals of Canada (GPC).

Corporate Cease Trade Orders or Bankruptcies

Except as described below, during the past ten years, none of the current directors and executive officers of Freehold is or has been a director, chief executive officer or chief financial officer of any company that: (i) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, while that person was acting in the capacity as director, chief executive officer or chief financial officer; (ii) was the subject of a cease trade order or similar order or an order that denied that company access to any exemption under securities legislation for a period of more than 30 consecutive days, after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. None of the directors or executive officers of Freehold is as at the date of the annual information form, or has been within 10 years before the date of the information circular, 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. Harrison was a director of Spyglass Resources Ltd. ("**Spyglass**") and resigned on November 26, 2015. Spyglass was placed into receivership on November 26, 2015. The common shares of Spyglass were suspended from trading on the TSX on December 31, 2015.

Personal Bankruptcies

None of the directors or executive officers of Freehold has nor any Shareholder holding sufficient number of securities of the Corporation to affect materially the control of the Corporation, 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 Freehold nor any Shareholder holding sufficient number of securities of the Corporation to affect materially the control of the Corporation, 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

The full text of the audit committee mandate is included in Appendix C of this AIF.

Composition of Audit Committee

Freehold's audit committee consists of Mr. Arthur Korpach (Chair), Mr. Gary Bugeaud and Mr. Aidan Walsh. All members of the audit committee are independent and financially literate as those terms are used under National Instrument 52-110 *Audit Committees*. See "*Governance – Board of Directors of Freehold*".

Pre-Approval Policies and Procedures

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

External Auditor Service Fees

The following table sets out the fees paid to KPMG LLP, the Corporation's external auditor, in the two most recently completed financial years.

	Year Ended December 31	
	2016	2015
Audit fees ⁽¹⁾	177,800	184,000
Audit-related fees ⁽²⁾	75,000	95,000
Tax fees ⁽³⁾	15,000	35,500
All other fees	-	-
Total	267,800	314,500

- (1) Audit fees consist of fees for the audit of Freehold's annual financial statements, reviews of interim consolidated financial statements for the first, second, and third quarters of the respective year, or services that are normally provided in connection with statutory and regulatory filings or engagements. Fees do not include administrative or Canadian Public Accountability Board surcharges.
- (2) Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of Freehold's financial statements and are not reported as Audit Fees. The services provided in this category includes work performed by Freehold's external auditors in connection with the bought deal financings completed by Freehold during 2015 and 2016.
- (3) Tax fees consist of fees for tax compliance and advisory services. During 2016 all fees were for compliance work relating to U.S. tax requirements. In 2015, \$15,000 was for U.S. tax requirements and the remainder was for advisory services.

THE MANAGER

Business of the Manager

The Manager provides comprehensive oil and gas company management and operational services to Freehold, FHT, and the Partnership. The Manager is a wholly-owned subsidiary of Rife. Pursuant to an agreement between Rife and the Manager dated November 25, 1996, Rife provides the Manager, on a contract basis, with all necessary personnel, equipment and facilities required to provide management and operational services to Freehold, FHT and the Partnership.

Employees

Freehold has no employees but rather is managed by the Manager pursuant to the Management Agreement. On December 31, 2016, Rife had 79 full and part-time employees in the Calgary office and 16 full-time employees in their field operations, the majority of whom are on contract to the Manager. These personnel also render services to Rife and Canpar.

Management Agreement

Pursuant to the Management Agreement, Freehold, FHT and the Partnership engaged the Manager to:

- administer all matters relating to the securities of Freehold, including the Common Shares, and the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold, FHT and the Partnership, including: (i) determining the total amount owing to Freehold and its subsidiaries and partnerships from third parties and conducting joint venture audits as required; (ii) determining the total amounts owing to Shareholders and arranging for dividends to Shareholders, subject to the supervision of Freehold; (iii) providing Shareholders with periodic reports on the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold and its subsidiaries and partnerships; and (iv) providing Shareholders with financial reports and tax information relating to the royalties, working interest properties and other interests in oil, natural gas and potash resources held by Freehold and its subsidiaries and partnerships;
- provide management services for the economic and efficient exploitation of oil and natural gas properties;

- operate oil and natural gas properties that Freehold and its subsidiaries and partnerships are entitled to operate and monitor the activities of third party operators;
- recommend, carry out and monitor property acquisitions and dispositions and exploitation and development programs for Freehold and its subsidiaries and partnerships;
- negotiate on behalf of Freehold and its subsidiaries and partnerships all exploitation and development agreements, operating agreements, working agreements, farmin and farmout agreements, leases and other documents relating to the exploitation of the oil and natural gas properties as may be advisable;
- recommend and negotiate banking arrangements for Freehold; and
- provide office space, office furnishings and equipment and personnel necessary for the proper administration of the assets of Freehold and its subsidiaries and partnerships.

In exercising its power and discharging its duties under the Management Agreement, the Manager will be required to exercise that degree of care, diligence and skill that a reasonably prudent advisor and manager in respect of oil and gas properties in western Canada would exercise in comparable circumstances.

The Management Agreement will continue in force until terminated by either the Manager or Freehold in accordance with the terms of the Management Agreement. The Manager can terminate the Management Agreement at any time after November 26, 2016 by providing six months written notice prior to the date of such termination. Freehold can terminate the Management Agreement at any time after May 26, 2020 by providing six months written notice prior to the date of such termination. Alternatively, Freehold can terminate the Management Agreement at any time after November 26, 2016 if the Manager and its affiliates cease to beneficially own or exercise control or direction over (in aggregate) 5% or more of the issued and outstanding Common Shares for a period of more than 90 consecutive days by providing six months written notice prior to termination. In addition, if a "Change of Control" (as defined in the Management Agreement) of Freehold occurs after November 26, 2016, Freehold will have the right to terminate the Management Agreement by providing written notice to the Manager within 90 days of such Change of Control together with making a payment to the Manager of \$2,000,000.

The Management Agreement may also be terminated by the Corporation at any time without the payment of compensation to the Manager if the Manager institutes bankruptcy proceedings, seeks relief under bankruptcy law, consents to the appointment of a receiver, voluntarily suspends transaction of its usual business, is declared bankrupt or insolvent, if a receiver is appointed in respect of the Manager, or if the Manager fails to carry out its material obligations under the Management Agreement and does not commence to cure such failure within 30 days of notice being given.

Proceeds relating to subscription offerings, royalty income and other revenues generated from or associated with any interest of Freehold may not be commingled with the funds of any other entity that is managed by the Manager.

The Manager will be paid the Management Fee for providing all of the management services. The Manager will be indemnified by Freehold in respect of certain damages that it may suffer in discharging its obligations under the Management Agreement provided that such damages do not arise from the fraud, wilful default, gross negligence or bad faith of the Manager.

The Board of Directors will review on an ongoing basis both the nature and extent of the services required of the Manager and the costs of providing the same. All amendments to the Management Agreement must be approved by a majority of the members of the Board of Directors.

Compensation

The Manager will be compensated as follows for providing services to the Corporation, FHT and the Partnership.

Management Fee

Under the terms of the Original Management Agreement the number of Common Shares payable quarterly to the Manager as Management Fee was adjusted quarterly based on the number of issued and outstanding Common Shares such that as the number of issued and outstanding Common Shares increased (excluding increases attributable to the issuance of Common Shares to the Manager as payment of the Management Fee) the Common Shares issuable to the Manager as payment of the Management Fee increased. As at December 31, 2016, the quarterly Management Fee was 71,912 Common Shares.

Under the terms of the Management Agreement, the Common Shares issuable as payment of the Management Fee will be gradually reduced over a period of seven years, as follows:

- through 2016 the Common Shares issuable on payment of the Management Fee was capped at 71,912 Common Shares paid quarterly;
- from 2017 through 2019 the Common Shares issuable on payment of the Management Fee will be capped at 55,000 Common Shares paid quarterly;
- in 2020 the Common Shares issuable on payment of the Management Fee will be capped at 41,250 Common Shares paid quarterly;
- in 2021 the Common Shares issuable on payment of the Management Fee will be capped at 27,500 Common Shares paid quarterly;
- in 2022 the Common Shares issuable on payment of the Management Fee will be capped at 13,750 Common Shares paid quarterly; and
- in 2023 and beyond the Common Shares issuable on payment of the Management Fee will be capped at 5,500 Common Shares paid quarterly.

In addition, the Management Agreement provides a mechanism for reducing the number of Common Shares issuable as payment of the Management Fee if the market price of the Common Shares at such time exceeds \$19.00 per Common Share. Pursuant to the Management Agreement, the Management Fee, at the option of Freehold, may be paid by (i) the issuance of Common Shares, or (ii) cash equal to the value of such Common Shares as determined by the market price of such Common Shares at such time.

General and Administrative Costs

The Manager is reimbursed for general and administrative costs incurred by Rife on behalf of the Corporation, FHT and the Partnership (in 2016 – 42%). General and administrative costs are generally charged to the Corporation, FHT and the Partnership by the Manager based on time spent and direct costs incurred in fulfilling the obligations of the Manager to the Corporation, FHT and the Partnership pursuant to the Management Agreement. Commencing in 2017, the allocation of costs based on time spent will be adjusted quarterly based on the actual percentage for the allocation of time spent by Rife's staff in the prior quarter (currently, the adjustment is only made once annually).

Long-Term Incentive Plan

The Corporation also accrues for its proportionate share (2014 grants – 34%; 2015 grants – 37%; 2016 grants – 42%) of a long-term incentive plan for employees of the Manager. The liability is estimated at the end of each quarter based on the quarter-end Common Share price and performance factors. The related compensation charges are recognized over the three-year vesting period.

Manager's Annual Bonus Plan

The Corporation pays its proportionate share (2016 bonus – 42%) of an annual cash bonus plan for employees of the Manager.

Directors' Deferred Share Unit Plan

The Deferred Share Unit Plan consists of fully vested Deferred Share Units, granted annually to non-management directors of the Corporation. Dividends to Shareholders declared by the Corporation prior to redemption are assumed to be reinvested in notional share units on the date of dividend.

Retirement Benefit

The Corporation participates in its proportionate share (in 2016 – 42%) of a retirement benefit for certain former employees of the Manager. The retirement benefit is payable in four equal instalments upon retirement. Service costs are amortized on a straight-line basis over the expected average remaining service lifetime.

Directors and Officers of the Manager

The name, province of residence, position held and principal occupation of each director and officer of the Manager are set out below:

Name and Province of Residence	Position with the Manager	Principal Occupation	Director or Officer of the Manager Since
Thomas J. Mullane Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer, Rife	July 18, 2012
Darren G. Gunderson Alberta, Canada	Vice-President, Finance and Chief Financial Officer and Director	Vice-President, Finance and Chief Financial Officer, Rife	July 2, 2007
David M. Spyker Alberta, Canada	Vice-President, Production	Vice-President, Production, Rife	November 28, 2016
Michael J. Stone Alberta, Canada	Vice-President, Land	Vice-President, Land, Rife	March 1, 2010
Alan G. Glessing Alberta, Canada	Controller	Controller, Rife	September 18, 2008
Karen C. Taylor Alberta, Canada	Corporate Secretary	Corporate Secretary, Rife	February 1, 2008

As at March 2, 2017, the directors and senior officers of the Manager as a group beneficially owned, directly or indirectly, or exercised control or direction over 35,465 Common Shares. Rife owns 100% of the outstanding shares in the capital of the Manager. All of the shares of Rife are owned by the CN Pension Trust Funds.

CONFLICTS OF INTEREST

There may be situations in which the interests of the Manager will conflict with those of the Shareholders. As part of the ordinary course of business of the Manager, the Manager may continue to acquire oil and natural gas properties on its own behalf and on behalf of persons other than Freehold. The Manager may manage and administer such properties, as well as enter into other types of energy-related management, advisory and investment activities. Thus, neither the Manager nor its management will carry on their full-time activities on behalf of Freehold and, when acting on its own behalf or on behalf of others, may at times act in contradiction to or in competition with the interests of the Shareholders. In addition, there are times when Freehold may participate or enter into transactions with Canpar and Rife.

In resolving such conflicts, decisions will be made by the Manager on a basis consistent with the objectives and financial resources of each group of interested parties, the time limitations on investment of such financial resources, and on the basis of operating efficiencies having regard to the then current holdings of properties of each group of interested parties all consistent with the duties of the Manager to each such group of persons. The Management Agreement contains provisions that require the Manager to make disclosure to the Board of Directors of the fact and substance of any particular conflict of interest and to use all reasonable efforts to resolve such conflicts of interest in a manner that will treat Freehold and the other interested party fairly taking into account all of the circumstances of Freehold and such interested party and to act honestly and in good faith in resolving such matters.

Although the Manager provides advisory and management services to Freehold, the Board of Directors supervises the management of the business and affairs of Freehold. The Board of Directors makes significant operational decisions and all decisions relating to: (i) the issuance of additional Common Shares; (ii) the acquisition and disposition of properties for a purchase price or proceeds in excess of \$10 million; (iii) the approval of capital expenditure budgets; (iv) the establishment of credit facilities; and (v) the determination of the amount of dividends to Shareholders.

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

The Board of Directors has implemented a related party transaction policy that sets out a specific process for consideration and Board approval of potential acquisitions, dispositions, joint ventures, farm-in arrangements and transactions of a similar nature that are outside the ordinary course of business ("**Related Party Transactions**") and involve Freehold and Rife and/or Canpar. The policy provides for negotiation of the terms of any Related Party Transaction by representatives of Freehold who do not have a material interest in such transaction. In addition, the policy requires that any such Related Party Transaction must be approved by members of the Board of Directors who do not have a material interest in such transaction.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of management of Freehold as at the date hereof, there are no legal proceedings that Freehold is a party to, or that any of Freehold's property is the subject of, that is material to Freehold, 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 Freehold if it involves a claim for damages and the amount involved, exclusive of interest and costs, does not exceed 10% of Freehold'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 Freehold 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 Freehold that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements Freehold entered into before a court relating to securities legislation or with a securities regulatory authority during Freehold's most recently completed financial year or during the current financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed below or herein, there were no material interests, direct or indirect, of any directors or executive officers of the Manager, directors or executive officers of Freehold, 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 Corporation.

The Manager and Rife are wholly-owned subsidiaries of the CN Pension Trust Funds, which held 25,353,264 Common Shares as at March 2, 2017, representing approximately 21.5% of the outstanding Common Shares. The Manager receives certain compensation for providing management services to the Corporation, FHT and the Partnership as described under "*The Manager*". All transactions during 2016 were in the normal course of operations and were

measured at the exchange amount, which is the amount of consideration established and agreed to by Freehold and the Manager.

As described under "*General Development of Business – Year Ended December 31, 2014*", concurrent with a bought deal offering completed by the Corporation on July 16, 2014, CN Pension Trust Funds purchased 557,621 Common Shares of Freehold at a price of \$26.90 per Common Share on a non-brokered private placement basis for gross proceeds of approximately \$15 million.

As described under "*General Development of Business – Year Ended December 31, 2014*", on November 13, 2014, Freehold and Rife entered into two agreements whereby Freehold purchased a 5% gross overriding royalty on Rife's Soda Lake and Lindbergh assets. Total consideration associated with the two deals was \$10.1 million, including adjustments.

As described under "*General Development of Business – Year Ended December 31, 2015*", on January 23, 2015 Freehold acquired Anderson for total consideration of \$35 million (subject to certain adjustments). David J. Sandmeyer a director of the Corporation at the time of the transaction was also a director and the Chairman of Anderson. Mr. Sandmeyer did not participate in any deliberations by the Board of Directors with respect to the Anderson acquisition and did not vote on any resolution of the Board of Directors to approve the Anderson acquisition.

As described under "*General Development of Business – Year Ended December 31, 2015*", concurrent with a bought deal offering completed by the Corporation on May 6, 2015, CN Pension Trust Funds purchased 1,833,334 Common Shares of Freehold at a price of \$18.00 per Common Share on a non-brokered private placement basis for gross proceeds of approximately \$33 million.

As described under "*General Development of Business – Year Ended December 31, 2015*", on November 9, 2015, Freehold, FHT and the Partnership entered into the Management Agreement with the Manager and Rife, which amended and restated the Original Management Agreement. On July 13, 2015 the Board of Directors established a special committee comprised of independent directors to review and consider the renewal or termination of the Original Management Agreement. The special committee retained financial advisors and independent legal counsel to provide financial and legal advice with respect to such matter. Following its review, the special committee concluded that it was in the best interests of the Corporation to amend the terms of the Original Management Agreement and proceeded to negotiate such amendments with Rife and the CN Pension Trust Funds, who also retained a financial advisor and independent legal counsel. As a result of the negotiations between Freehold and Rife a number of amendments were made to the Original Management Agreement, including amendments of the provisions relating to the payment of the Management Fee to the Manager and the provisions relating to termination. For additional details on the terms of the Management Agreement, see "*The Manager – Management Agreement*". In addition, the full text of the Management Agreement has been filed on SEDAR www.sedar.com.

As described under "*General Development of Business – Year Ended December 31, 2016*", concurrent with a bought deal offering completed by the Corporation on May 25, 2016, CN Pension Trust Funds purchased 1,732,000 Common Shares of Freehold at a price of \$11.55 per Common Share on a non-brokered private placement basis for gross proceeds of approximately \$20 million.

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and Toronto, Ontario acts as the transfer agent and registrar for the Common Shares.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by the Corporation within the most recently completed financial year, or before the most recently completed financial year but which are still in effect, are the following:

- the Governance Agreement dated December 31, 2010, as described under the heading "*Governance – Governance Agreement*";

- the Management Agreement dated November 9, 2015, as described under the heading "*The Manager – Management Agreement*"; and
- the credit facility between the Corporation, FHT and the Partnership and their lenders dated January 23, 2015 and amended on May 14, 2015 and May 20, 2016 as described under "*Borrowing*".

INTEREST 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 Corporation during, or relating to, the Corporation'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, Trimble, our independent engineering evaluators, and Seaton-Jordan, our independent land evaluation specialists.

Interest of Experts

KPMG LLP are the auditors of the Corporation and have confirmed they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

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

In addition, none of the aforementioned persons or companies, nor any partner, director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Manager or Freehold or any of our associate or affiliate entities.

ADDITIONAL FINANCIAL AND OTHER INFORMATION

Additional information about the Corporation may be found on SEDAR at www.sedar.com. Information about remuneration and indebtedness of directors and officers of Freehold and the Manager, principal holders of the Common Shares and securities authorized for issuance under security-based compensation of the Corporation, will be contained in the Management Information Circular of the Corporation to be dated on or about March 23, 2017, which relates to the Annual Meeting of Shareholders to be held on May 10, 2017. Additional financial information is provided in Freehold's consolidated financial statements for the year ended December 31, 2016 and the accompanying management's discussion and analysis.

For copies of our consolidated financial statements of the Corporation and accompanying management's discussion and analysis and the Management Information Circular and additional copies of the AIF (in certain circumstances reasonable fees may apply) please contact:

Corporate Secretary
Freehold Royalties Ltd.
Suite 400, 144 – 4th Avenue S.W.
Calgary, Alberta T2P 3N4
Telephone: 403-221-0802
Toll Free: 1-888-257-1873
Fax: 403-221-0888

APPENDIX A

Form 51-101F2

Report on Reserves Data by Independent Qualified Reserves Evaluators

To the Board of Directors of Freehold Royalties Ltd. (the "**Corporation**") and Rife Resources Management Ltd., as manager of the Corporation:

1. We have evaluated the Corporation'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 Corporation'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%, included in the reserves data of the Corporation evaluated for the year ended December 31, 2016, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation's management:

Independent Qualified Reserves Evaluator	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) (\$000s)			
			Audited	Evaluated	Reviewed	Total
Trimble Engineering Associates Ltd.	Reserve and Present Worth Appraisal of Certain Oil and Gas Properties At December 31, 2016 Dated January 23, 2017	Canada	0	\$880,580	0	\$880,580

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
7. We have no responsibility to update our 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 judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Trimble Engineering Associates Ltd., Calgary, Alberta, Canada, March 2nd, 2017.

Per: (signed) "Stephen C. Trimble"
 Stephen C. Trimble, P.Eng.
 President & Managing Director

APPENDIX B

Form 51-101F3

Report of Management and Directors on Oil and Gas Disclosure

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

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented in Appendix A of this Annual Information Form.

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

- a. reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;
- b. met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- c. reviewed the reserves data with management and the independent qualified reserves evaluator.

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

- a. the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
- b. the filing of Form 51-101F2, which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data or prospective resources data; and
- c. the content and filing of this report.

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

(signed) "Thomas J. Mullane"
Thomas J. Mullane
President, Chief Executive Officer and Director

(signed) "David M. Spyker"
David M. Spyker
Vice-President, Production

(signed) "Aidan M. Walsh"
Aidan M. Walsh
Director and Chair, Reserves Committee

(signed) "Susan M. MacKenzie"
Susan M. MacKenzie
Director and Member, Reserves Committee

DATED as of this 2nd day of March, 2017.

APPENDIX C

Audit Committee Mandate

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Freehold Royalties Ltd. ("**Freehold**") to which the Board has delegated certain responsibilities for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee are as follows:

1. to assist directors in meeting their responsibilities, especially for accountability, in respect of the preparation and disclosure of the financial statements of Freehold and related matters;
2. to provide better communication between directors and the external auditors;
3. to enhance the external auditors' independence;
4. to increase the transparency, credibility and objectivity of financial reporting; and
5. to strengthen the role of the independent directors by facilitating in-depth discussions between directors on the Committee, management and the external auditors.

Membership of Committee

1. The Committee will be comprised of at least three directors, all of whom are independent (as such term is used in National Instrument 52-110 – Audit Committees ("**NI 52-110**")).
2. The Board will have the power to appoint the Committee Chair.
3. All of the members of the Committee will be financially literate. The Board has adopted the definition for financial literacy used in NI 52-110.

Meetings

1. At all meetings of the Committee, every question will be decided by a majority of the votes cast. In case of an equality of votes, the Committee Chair is not entitled to a second or deciding vote.
2. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board.
3. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer ("**CFO**") will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Committee Chair.
4. The Committee will forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board.
5. The Committee will 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.

6. The Committee will hold an in-camera session, without members of management or management directors, at each meeting. The Committee may invite other directors, members of management, and advisors to attend all or part of any in-camera session, as it deems advisable.

Mandate and Responsibilities

The mandate and responsibilities of the Committee will be as set forth below:

1. Oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting;
2. Satisfy itself on behalf of the Board with respect to Freehold's internal control systems, which include:
 - (a) identifying, monitoring and mitigating business risks; and
 - (b) ensuring compliance with legal, ethical and regulatory requirements;
3. Review the annual and quarterly financial statements of Freehold prior to their submission to the Board for approval. The process should include but not be limited to:
 - (a) reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
 - (b) reviewing significant accruals, reserves or other estimates such as impairment testing;
 - (c) reviewing accounting treatment of unusual or non-recurring transactions;
 - (d) ascertaining compliance with covenants under loan agreements;
 - (e) reviewing adequacy of reclamation provisions;
 - (f) reviewing disclosure requirements for commitments and contingencies;
 - (g) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
 - (h) reviewing unresolved differences between management and the external auditors; and
 - (i) obtaining explanations of significant variances with comparative reporting periods;
4. Review the financial statements, prospectuses, management discussion and analysis, annual information forms, earnings news releases, and all public disclosure containing audited or unaudited financial information before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Freehold's disclosure of all other financial information and will periodically assess the accuracy of those procedures;
5. Recommend to the Board the annual appointment of external auditors, and in so doing:
 - (a) annually review the performance and independence of the external auditors;
 - (b) review the terms of engagement of the auditor, including the compensation of the auditors;
 - (c) confirm that the auditors will report directly to the Committee;
 - (d) when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
 - (e) review and approve any non-audit services to be provided by the auditors' firm and consider the impact on the independence of the auditors;
6. Review with external auditors, and the internal auditor if one is appointed by Freehold, their assessment of the internal controls of Freehold, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their audit plan and, upon completion of the audit, their reports upon the financial statements of Freehold and its subsidiaries;
7. Pre-approve all non-audit services to be provided to Freehold or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time;
8. Review, on an annual basis, the risk management policies and procedures of Freehold, including hedging, litigation and insurance, other than directors and officers liability insurance;

9. Review and approve management's hiring policies regarding current and former partners and employees of the present and former external auditor;
10. Establish procedures for:
 - (a) the receipt, retention and treatment of complaints received by Freehold regarding accounting, internal accounting controls or auditing matters; and
 - (b) the confidential, anonymous submission by employees of Rife Resources Management Ltd. (the "**Manager**") of concerns regarding questionable accounting or auditing matters;
11. To review and report to the Board on the procedures in place for reporting and certification under the *Extractive Sector Transparency Measures Act* (Canada) ("**ESTMA**") at such time as Freehold is required to comply with ESTMA.
12. The Committee will have the authority to investigate any financial activity of Freehold. All employees of the Manager are to cooperate as requested by the Committee; and
13. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling their responsibilities at the expense of Freehold without any further approval of the Board.