



2012 Annual Information Form

March 7, 2013

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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 and the number of wells on which Freehold expects to have abandonment and reclamation obligations;
- plans for development of undeveloped reserves;
- the funding and payment of future dividends;
- the expectations for the funding of capital expenditures;
- 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;
- capital expenditure programs and the funding thereof;
- the anticipated development of certain lands acquired by Freehold in recent years;
- 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 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 may require the Manager to assume operatorship on behalf of Freehold;
- 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;

- the expectation that approximately half of our 2013 capital budget will be allocated to Freehold's working interest properties in the Southeast Saskatchewan area; and
- the expectation that approximately half of our 2013 capital budget will be allocated to various other working interest properties, primarily on Freehold's mineral title lands in the Lloydminster area (heavy oil) and in west central Alberta (Cardium light oil).

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 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 (“boe”)

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:

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

“**Arrangement**” means the plan of arrangement involving, among others, the Trust, Freehold, Freehold Resources, the Partnership and holders of Trust Units initiated on December 31, 2010 and completed on January 1, 2011 under the ABCA which resulted in the conversion of the Trust into a public dividend paying corporation, being Freehold, that owns all of the existing assets and assumed all of the existing liabilities of the Trust.

“**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.

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

“**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.

“**Deferred Trust Unit Plan**” means the deferred trust unit plan approved by holders of Trust Units on May 10, 2006 for non-management directors of Freehold Resources.

“**Deferred Trust Units**” means the deferred trust units of the Trust issued pursuant to the Deferred Trust Unit Plan.

“**DRIP**” means the dividend reinvestment plan of Freehold.

“**Freehold Resources**” means, prior to completion of the Arrangement, Freehold Resources Ltd., a corporation incorporated under the ABCA and a wholly-owned subsidiary of the Trust and, after completion of the Arrangement, Freehold Resources Ltd., a corporation created upon the amalgamation of Freehold Resources Ltd. and 1163177 Alberta Ltd. pursuant to the Arrangement and a wholly-owned subsidiary of the Corporation.

“**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.

“**Management Agreement**” means the amended and restated agreement dated January 1, 2011 among the Manager, the Corporation, Freehold Resources and the Partnership pursuant to which the Manager provides management services to the Corporation, Freehold Resources 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.

“**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.

“**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*.

“**Partnership**” means Freehold Royalties Partnership, a general partnership formed under the laws of Alberta.

“**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 and potash resources.

“**Royalty Lands**” means the lands from which the Corporation derives Royalty Income.

“**Seaton-Jordan**” means Seaton-Jordan & Associates Ltd., independent mineral management consultants 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 24, 2013 prepared by Trimble, evaluating the oil, natural gas, natural gas liquids, and sulphur reserves attributable to the Corporation as at December 31, 2012.

“**Trust**” means Freehold Royalty Trust, an unincorporated open end investment trust established under the laws of Alberta pursuant to an amended and restated trust indenture dated May 10, 2006 between Computershare Trust

Company of Canada, as trustee, and Freehold Resources, as amended from time to time, which was dissolved pursuant to the Arrangement.

“**Trust Units**” means the trust units of the Trust.

“**TSX**” means the Toronto Stock Exchange.

“**USA**” means the amended and restated unanimous shareholder agreement dated December 31, 2004 among Freehold Resources, the Manager and Computershare Trust Company of Canada, as trustee, which was terminated on December 31, 2010.

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 the Trust pursuant to the Arrangement.

Freehold was formed upon the amalgamation of Freehold Royalties Ltd. and 1555014 Alberta Ltd. pursuant to the Arrangement. Together with Freehold Resources and the Partnership, Freehold carries on the business formerly carried on by the Trust and its subsidiaries, trusts and partnerships. 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, Freehold Resources and the Partnership. The head, principal and registered office of Freehold is located at Suite 400, 144 – 4th Avenue SW, Calgary, Alberta, T2P 3N4.

Freehold Resources Ltd.

Freehold Resources was formed upon the amalgamation of Freehold Resources and 1163177 Alberta Ltd. pursuant to the Arrangement. All of the issued and outstanding shares of Freehold Resources are held by Freehold. The head, principal and registered office of Freehold Resources 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, Freehold Resources 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, Freehold Resources 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, Freehold Resources 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 the personnel utilized by the Manager have extensive experience with the assets underlying Freehold’s royalty and working interest properties and other oil, natural gas and potash resources. In addition, Rife manages two private corporations that are engaged in similar business ventures as Freehold. To effectively manage these private corporations and Freehold, Freehold Resources and the Partnership, Rife has assembled a larger, more diversified and more experienced staff than Freehold could otherwise retain to manage its assets. Management of Freehold believes these organizational and synergistic benefits are advantageous to the 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 26% of the outstanding Common Shares and as a result has the right to nominate two individuals as directors of Freehold. The number of directors of the Corporation is presently set at eight.

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 Freehold Resources 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.

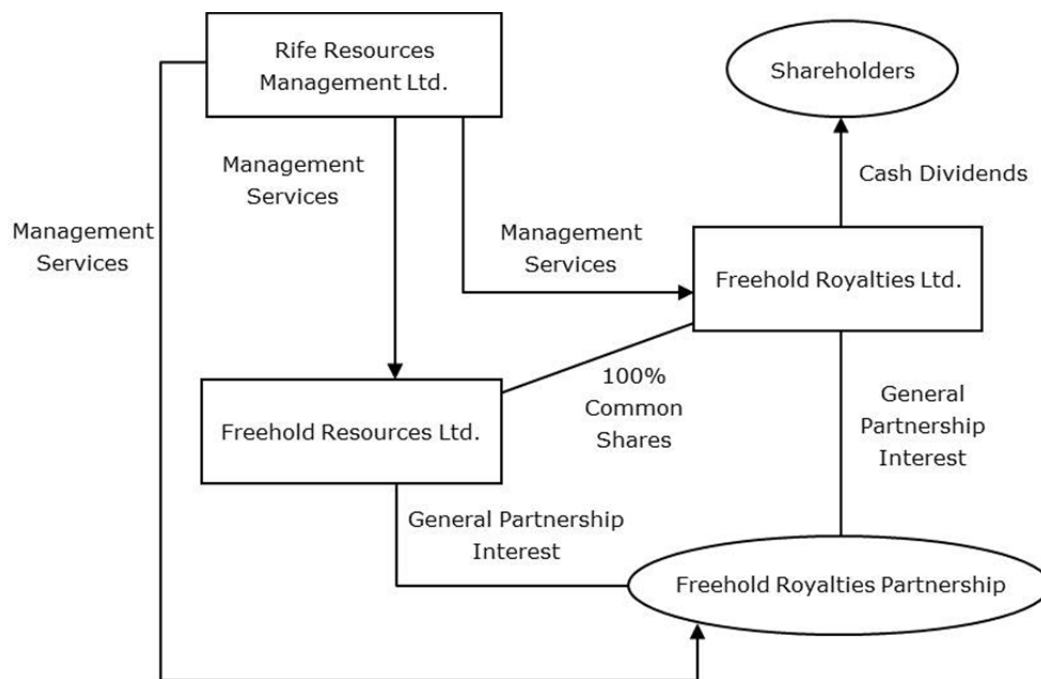
Structure of the Corporation

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 Resources Ltd.	100%	Corporation	Alberta
Freehold Royalties Partnership	100%	General Partnership	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.

The Arrangement – Transformation to a Corporation

Pursuant to the Arrangement, which was initiated on December 31, 2010 and completed on January 1, 2011, involving Freehold, the Trust, Freehold Resources, the Partnership, the Manager and certain subsidiaries and trusts of the Trust and holders of Trust Units, Freehold, directly or indirectly, acquired all of the assets and assumed all of the liabilities of the Trust. Freehold’s business model did not change as a result of the reorganization of the Trust into a corporate structure. Freehold has continued, and expects to continue in the future, to allocate cash flows as the Trust historically did prior to the Arrangement. Freehold allocates cash flow primarily for capital expenditures, acquisitions, periodic debt repayments and dividends (which are based on after-tax cash flow). Prior to completion

of the Arrangement, the Trust was a reporting issuer in all the provinces of Canada and the Trust Units were listed for trading on the TSX. Following completion of the Arrangement, the Trust Units were de-listed from trading on the TSX and the Trust ceased to be a reporting issuer.

Pursuant to the terms of the Arrangement, former holders of Trust Units received one Common Share for each one Trust Unit held. The former holders of Trust Units received an aggregate of 59,181,312 Common Shares in exchange for all the outstanding Trust Units.

Freehold retained the management team and personnel from Freehold Resources. The members of the board of directors of Freehold Resources became the members of the Board of Directors. The Arrangement did not trigger any change of control or other termination payments pursuant to any employment agreements or arrangements within Freehold Resources nor did it trigger any payments to the Manager.

Following the Arrangement, the Manager continued to provide management services to Freehold. The compensation arrangements with the Manager were not changed from the compensation arrangements with the Manager that existed prior to the Arrangement other than the Manager is entitled to receive Common Shares instead of Trust Units as payment of the Management Fee. To facilitate the continued relationship between the Manager and Freehold, the Management Agreement was amended and restated as a step in the Arrangement.

Pursuant to the Arrangement, the USA was terminated and the Manager and Freehold entered into the Governance Agreement. The USA provided that the holders of Trust Units were entitled to elect the majority of the members of the board of directors of Freehold Resources, and the Manager was entitled to elect the balance of the members of the board of directors of Freehold Resources. The Manager agreed to the reduction of its right under the USA to the right to nominate, rather than appoint, directors of Freehold to allow the Common Shares to be listed as “common shares” and not “restricted voting shares” on the TSX. 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 provides the Manager with the right to have an observer present at all meetings of directors of Freehold.

In connection with the Arrangement, Freehold, in effect, assumed the obligations of the Trust in respect of outstanding Deferred Trust Units. The Arrangement did not trigger the acceleration of the vesting of any outstanding Deferred Trust Units. On completion of the Arrangement, holders of Deferred Trust Units were thereafter entitled to receive Common Shares, rather than Trust Units, upon redemption of such Deferred Trust Units after the effective date of the Arrangement, on the same basis as Trust Units were previously issuable on exercise thereof. In conjunction with the implementation of the Arrangement, holders of Trust Units approved the Deferred Share Unit Plan.

History and Development Prior to the Arrangement

The following is a description of the general development of the business of the Trust, including acquisitions, over its last completed financial year prior to the Arrangement.

Year Ended December 31, 2010

On February 17, 2010, we closed an acquisition of certain royalty interests encompassing 319,681 gross acres in Alberta, Saskatchewan, and British Columbia for \$39 million. The acquisition represented the creation of a 5% overriding royalty on 11 producing properties and the assignment to Freehold of eight small gross overriding royalty interests. We anticipate further development on these lands over the next several years.

History and Development Following the Arrangement

The following is a description of the general development of the business of the Corporation following the completion of the Arrangement.

Year Ended December 31, 2011

On September 30, 2011, we closed an acquisition of certain royalty interests for \$7.3 million, after closing adjustments, which added approximately 125 boe per day of primarily light oil to our royalty production base commencing in the fourth quarter of 2011. We acquired a 10% gross overriding royalty interest on 5,048 gross acres of land in the Peace River area of Northwest Alberta. The agreement provides for additional payments to the vendor of up to \$3.2 million if additional wells are drilled before December 31, 2013. The acquisition supported our strategy of focusing on oil and gas royalties and was accretive on a debt-adjusted per share basis. The acquisition was effective July 1, 2011 and was funded through our existing credit facilities.

Year Ended December 31, 2012

On January 17, 2012, we completed the acquisition of royalty interests on certain producing and non-producing lands in Alberta, British Columbia and Saskatchewan for \$49.3 million after closing adjustments. The acquisition was funded with money drawn on our credit facilities. As a result of the acquisition, we will receive an average 4% contractual gross overriding royalty on over 250,000 gross acres (including over 51,000 undeveloped acres valued at \$1.3 million).

On February 29, 2012, we issued 3,450,000 Common Shares under a short-form prospectus offering at a price of \$20.50, which included 450,000 Common Shares issued pursuant to an over-allotment option provided to the underwriters. The net proceeds of approximately \$67.6 million were used to reduce bank debt.

On August 31, 2012, we acquired approximately 6,100 net acres of leased mineral title lands in Alberta and Saskatchewan. The lands and 90 boe per day (21% royalty production) were purchased for \$10.9 million after closing adjustments. The acquisition was funded with money drawn on our credit facilities.

Significant Acquisitions

During the year ended December 31, 2012, the Corporation did not complete any acquisitions that would be considered significant pursuant to NI 51-102.

BUSINESS OF THE CORPORATION**Overview**

Freehold and its subsidiaries and partnerships carry on the business formerly carried on by the Trust through its subsidiaries, partnerships and trusts prior to the Arrangement. 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 interests in more than 30,000 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.

Management Policies and Acquisition Strategy

The Manager manages Freehold, Freehold Resources and the Partnership in accordance with the Management Agreement. All activities undertaken by the Manager are directed towards maximizing dividends to be paid to the Shareholders while striving to acquire appropriate assets to provide long-term growth in the value of Freehold. These two objectives are fundamental to the operation of Freehold and are pursued to maximize value to the Shareholders.

The Manager utilizes its staff's extensive experience and employs prudent oil and gas business practices to increase the assets of Freehold through the acquisition of both royalty and working 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 of a low risk nature and that have long-term value enhancement potential. Properties to be acquired may be operated by competent third parties or may require the Manager to assume operatorship on behalf of Freehold.

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

- Quality Assets: producing properties with an established production history and low reserve risk;
- Attractive Returns: accretive on a per-share basis;
- Reasonable Assumptions: commodity price and exchange rate assumptions from an independent engineering firm acceptable to the Board of Directors;
- High Operating Netbacks; and
- Long Economic Life: an expected economic life of not less than ten years.

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 including risk profile, technical upside, reserve life index and asset quality.

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, 2012, and the preparation date of the Statement is January 24, 2013.

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101 F2 and the Report of Management and Directors on Reserves Data and Other Information in Form 51-101 F3 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, 2012 contained in the Trimble Report. The Reserves Data summarizes the oil, natural gas, natural gas liquids, and sulphur reserves of Freehold and the net present values of future net revenue for these reserves using forecast prices and costs. 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, natural gas liquids, and sulphur reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas, natural gas liquids, and sulphur reserves may be greater than or less than the estimates provided herein.

Forecast Prices and Costs

**SUMMARY OF OIL AND GAS RESERVES
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS**

Reserves Category	Light and Medium Oil		Heavy Oil		Total Crude Oil	
	Gross ⁽¹⁾ (Mbbls)	Net (Mbbls)	Gross ⁽¹⁾ (Mbbls)	Net (Mbbls)	Gross ⁽¹⁾ (Mbbls)	Net (Mbbls)
Proved						
Developed producing	1,754	3,490	827	4,150	2,581	7,640
Developed non-producing	73	64	-	6	73	70
Undeveloped	-	-	28	23	28	23
Total proved	1,826	3,554	856	4,178	2,682	7,733
Probable	1,346	2,301	916	3,197	2,262	5,498
Total proved plus probable	3,173	5,855	1,771	7,376	4,944	13,231

Reserves Category	Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross ⁽¹⁾ (MMcf)	Net (MMcf)	Gross ⁽¹⁾ (Mbbls)	Net (Mbbls)	Gross ⁽¹⁾ (Mboe)	Net (Mboe)
Proved						
Developed producing	4,024	33,628	146	841	3,398	14,085
Developed non-producing	59	794	7	7	90	209
Undeveloped	-	4,314	-	46	28	788
Total proved	4,083	38,736	154	893	3,516	15,082
Probable	3,042	20,212	124	476	2,893	9,343
Total proved plus probable	7,125	58,949	277	1,369	6,409	24,425

- (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 Corporation is unique in that the majority of our 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.

**SUMMARY OF
NET PRESENT VALUES
OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS**

Reserves Category	Before Income Taxes, Discounted at (% per year)				
	0% (\$000s)	5% (\$000s)	10% (\$000s)	15% (\$000s)	20% (\$000s)
Proved					
Developed producing	730,246	537,722	431,272	364,055	317,704
Developed non-producing	4,259	2,773	1,986	1,517	1,211
Undeveloped	23,328	16,185	11,818	8,958	6,987
Total proved	757,833	556,679	445,076	374,529	325,902
Probable	564,863	295,635	193,236	142,680	112,973
Total proved plus probable	1,322,696	852,314	638,312	517,209	438,875

Reserves Category	After Income Taxes, Discounted at (% per year)				
	0%	5%	10%	15%	20%
	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)
Proved					
Developed producing	616,012	453,317	363,687	307,156	268,186
Developed non-producing	3,194	2,060	1,458	1,099	865
Undeveloped	17,434	12,070	8,789	6,639	5,158
Total proved	636,639	467,447	373,934	314,894	274,210
Probable	420,690	219,454	142,981	105,240	83,075
Total proved plus probable	1,057,329	686,902	516,915	420,134	357,284

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS**

(\$000s)	Reserves Category	
	Proved	Proved Plus Probable
Royalty Income	660,266	1,136,234
Revenue from working interest properties	269,358	506,074
Royalty expense on working interest properties	(40,759)	(83,190)
Operating costs	(121,380)	(214,202)
Development costs	(1,441)	(12,560)
Well abandonment and reclamation costs	(8,212)	(9,661)
Future net revenue before income taxes	757,833	1,322,696
Future income taxes	(121,194)	(265,367)
Future net revenue after income taxes	636,639	1,057,329

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS**

Reserves Category	Production Group	Future Net Revenue Before Income Taxes	
		Discounted at 10% per year (\$000s)	Unit Value ⁽¹⁾ (\$)
Proved	Light and Medium Oil (including solution gas and other by-products)	162,260	46.02/bbl
	Heavy Oil (including solution gas and other by-products)	171,014	40.93/bbl
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	111,802	3.29/Mcf
	Total Proved	445,076	29.51/boe
Proved plus probable	Light and Medium Oil (including solution gas and other by-products)	239,308	41.17/bbl
	Heavy Oil (including solution gas and other by-products)	247,595	33.57/bbl
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	151,410	2.95/Mcf
	Total Proved Plus Probable	638,312	26.13/boe

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

Definitions and Other Notes

1. Columns may not add due to rounding.
2. The oil, natural gas, natural liquids, and sulphur reserve 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, 2012 utilized in the Trimble Report were as follows:

FORECAST PRICES USED IN ESTIMATES AS OF DECEMBER 31, 2012

Year	Oil					Natural Gas	Natural Gas Liquids FOB Field Gate			Inflation Rate	Exchange Rate
	WTI Cushing Oklahoma	Edmonton Par Price 40° API	Hardisty Heavy 12° API	Hardisty Bow River 24.9° API	Western Canada Select 20.5° API	AECO 30 Day Spot	Propane	Butane	Pentane		
	\$US/ bbl	\$Cdn/ bbl	\$Cdn/ bbl	\$Cdn/ bbl	\$Cdn/ bbl	\$Cdn/ MMBtu	\$Cdn/ bbl	\$Cdn/ bbl	\$Cdn/ bbl	%/ Year	\$US/\$ Cdn
2013	89.63	84.55	61.72	70.18	69.33	3.31	47.15	63.02	90.53	1.50	1.00
2014	89.93	89.84	66.48	75.47	74.57	3.72	50.22	66.96	96.19	1.50	1.00
2015	88.29	88.21	65.27	74.09	73.21	3.91	49.45	65.74	94.44	1.50	1.00
2016	95.52	95.43	72.53	81.12	80.17	4.70	53.82	71.13	102.18	1.50	1.00
2017	96.96	96.87	73.62	82.34	81.37	5.32	54.97	72.20	103.71	1.50	1.00
2018	98.41	98.32	74.72	83.57	82.59	5.40	55.74	73.28	105.27	1.50	1.00
2019	99.89	99.79	75.84	84.82	83.83	5.49	56.52	74.38	106.85	1.50	1.00
2020	101.38	101.29	76.98	86.10	85.08	5.58	57.31	75.50	108.45	1.50	1.00
2021	102.91	102.81	78.14	87.39	86.36	5.67	58.12	76.63	110.08	1.50	1.00
2022	104.45	104.35	79.31	88.70	87.66	5.76	58.93	77.78	111.73	1.50	1.00
2023	106.02	105.92	80.50	90.03	88.97	5.85	55.84	78.95	113.40	1.50	1.00
Thereafter, per year:											
	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	1.50	1.00

The following table provides the historical weighted average prices realized by Freehold for the year ended December 31, 2012:

FREEHOLD WEIGHTED AVERAGE PRICES YEAR ENDED DECEMBER 31, 2012

	Light and Medium Oil (\$/bbl)	Heavy Oil (\$/bbl)	Natural Gas (\$/Mcf)	Natural Gas Liquids (\$/bbl)	Oil Equivalent (\$/boe)
Freehold weighted average price	81.32	64.57	1.90	58.16	51.00

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. "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:
- 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;
 - 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;
 - 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
 - provide improved recovery systems.
6. "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.
7. 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)
2013	773	5,538
2014	519	6,525
2015	29	131
2016	29	117
2017	30	119
Remainder	61	130
Total	1,441	12,560

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 will not be materially affected by the costs of funding the future development expenditures.

- The forecast price and cost assumptions assume the continuance of current laws and regulations.
- The extent and character of all factual data supplied to Trimble were accepted by Trimble as represented. No field inspection was conducted.
- 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. Due to the Corporation's unique asset base, we feel that they do not provide adequate information and are potentially

misleading. Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include any royalties receivable. Net reserves are working interests minus royalties payable plus royalties receivable. As 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 others in our industry. 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 Oil			Heavy Oil		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus
			Probable (Mbbbls)			Probable (Mbbbls)
December 31, 2011	1,690	1,009	2,699	839	666	1,505
Extensions	391	324	715	186	121	306
Improved recovery	-	-	-	-	-	-
Technical revisions	278	(137)	141	52	(134)	(81)
Discoveries	-	-	-	-	-	-
Acquisitions	5	149	154	50	265	314
Dispositions	-	-	-	-	-	-
Economic factors	(1)	1	(1)	1	(2)	(1)
Production	(537)	-	(537)	(272)	-	(272)
December 31, 2012⁽¹⁾	1,826	1,346	3,173	856	916	1,771

	Natural Gas			Natural Gas Liquids		
	Proved (MMcf)	Probable (MMcf)	Proved Plus	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus
			Probable (MMcf)			Probable (Mbbbls)
December 31, 2011	4,339	3,003	7,342	182	127	309
Extensions	35	28	63	-	-	-
Improved recovery	-	-	-	-	-	-
Technical revisions	756	(370)	386	7	(16)	(9)
Discoveries	-	-	-	-	-	-
Acquisitions	59	397	456	3	13	16
Dispositions	-	-	-	-	-	-
Economic factors	(39)	(16)	(55)	-	-	-
Production	(1,067)	-	(1,067)	(38)	-	(38)
December 31, 2012⁽¹⁾	4,083	3,042	7,125	154	124	277

	Oil Equivalent			
		Proved (Mboe)	Probable (Mboe)	Proved Plus
				Probable (Mboe)
December 31, 2011		3,434	2,303	5,736
Extensions		583	449	1,032
Improved recovery		-	-	-
Technical revisions		463	(348)	115
Discoveries		-	-	-
Acquisitions		68	493	560
Dispositions		-	-	-
Economic factors		(7)	(4)	(11)
Production		(1,024)	-	(1,024)
December 31, 2012⁽¹⁾		3,516	2,893	6,409

(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 Oil			Heavy Oil		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2011	3,445	1,885	5,330	4,533	2,841	7,373
Extensions	569	426	995	324	199	523
Improved recovery	-	-	-	-	-	-
Technical revisions	319	(178)	142	167	(74)	93
Discoveries	-	-	-	-	-	-
Acquisitions	87	165	253	46	232	278
Dispositions	-	-	-	-	-	-
Economic factors	16	3	19	5	-	5
Production	(883)	-	(883)	(897)	-	(897)
December 31, 2012⁽¹⁾	3,554	2,301	5,855	4,178	3,197	7,376

	Natural Gas			Natural Gas Liquids		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2011	32,560	17,113	49,673	802	405	1,206
Extensions	810	523	1,333	42	27	69
Improved recovery	-	-	-	-	-	-
Technical revisions	771	(1,677)	(906)	42	(31)	11
Discoveries	-	-	-	-	-	-
Acquisitions	11,765	4,263	16,028	206	75	281
Dispositions	-	-	-	-	-	-
Economic factors	(21)	(10)	(31)	-	-	-
Production	(7,149)	-	(7,149)	(198)	-	(198)
December 31, 2012⁽¹⁾	38,736	20,212	58,949	893	476	1,369

	Oil Equivalent		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2011	14,206	7,982	22,189
Extensions	1,071	738	1,809
Improved recovery	-	-	-
Technical revisions	657	(562)	95
Discoveries	-	-	-
Acquisitions	2,300	1,183	3,483
Dispositions	-	-	-
Economic factors	17	1	19
Production	(3,169)	-	(3,169)
December 31, 2012⁽¹⁾	15,082	9,343	24,425

(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.

For the years ended December 31, 2010 and 2011, there were no proved undeveloped reserves assigned to the Corporation. At December 31, 2012, proved undeveloped reserves assigned in the Trimble Report were 5.2% of the total proved reserves assigned.

For the years ended December 31, 2010 to 2011, probable undeveloped reserves were less than 0.3% of total proved plus probable reserves assigned in the Trimble report. At December 31, 2012 probable undeveloped reserves were 3.8% of the total proved plus probable reserves assigned in the Trimble Report.

The undeveloped net reserves at December 31, 2012, are largely associated with acquisitions during 2012. The light, medium and heavy oil net reserves are expected to be developed over the next two years. Development of the undeveloped natural gas and natural gas liquids net reserves will be dependent on commodity pricing and it may be three or more years until they are developed.

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, 2012, 2011, and 2010, and in the aggregate before that time, based on forecast prices and costs:

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

Year	Light and Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)
Prior	-	-	-	-
2010	-	-	-	-
2011	-	-	-	-
2012	-	23	4,314	46
Total Booked for Current Year	-	23	4,314	46

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

Year	Light and Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)
Prior	-	12	634	-
2010	-	-	-	-
2011	46	-	50	-
2012	138	233	6,641	77
Total Booked for Current Year	184	245	7,325	77

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; production and development costs, severance and excise taxes, and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- 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.

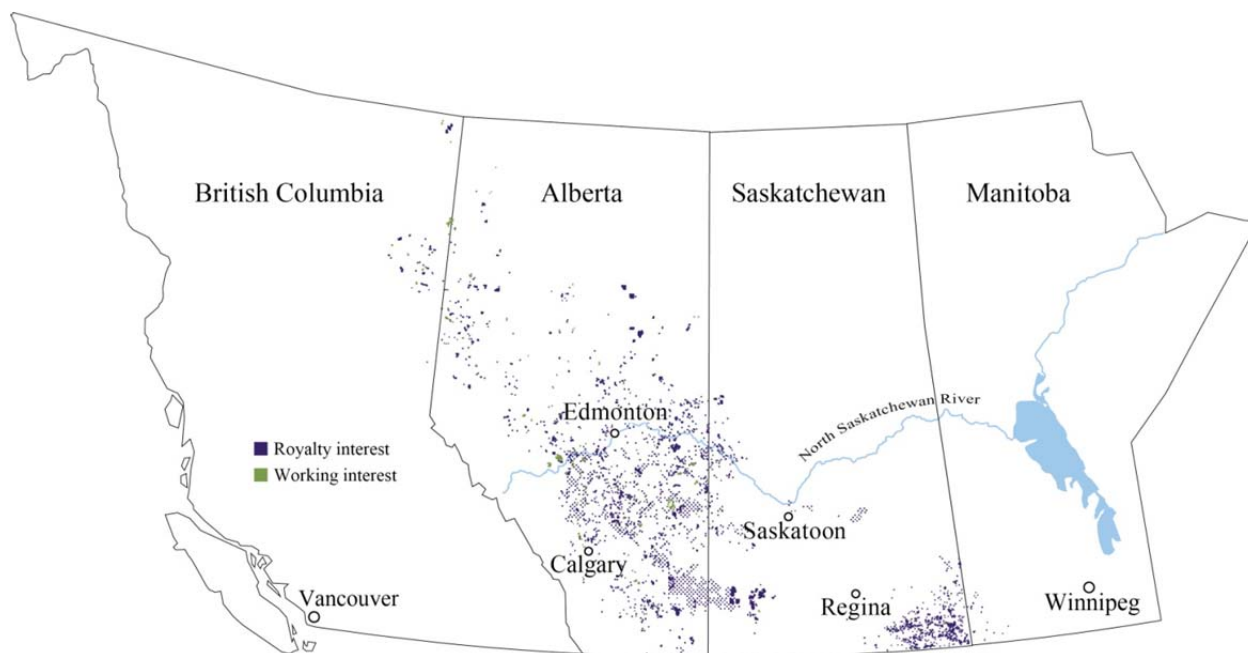
These factors and assumptions were based on prices at the date the evaluation was prepared. If these factors and assumptions prove to be inaccurate, the actual results may vary materially from the reserve estimates. Many of these factors are subject to change and are beyond the Corporation's control. 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 3.0 million gross acres at December 31, 2012. The majority of our land (69%) is in Alberta, with 17% in Saskatchewan, 9% in Ontario, 5% in British Columbia, and less than 1% in Manitoba. We also own royalty interests in seven potash mines in Saskatchewan.

Producing lands include Crown, freehold, unitized and non-unitized oil and natural gas and potash production. The properties are operated by experienced operators, including, among others: Angle Energy Inc., Apache Canada Ltd., ARC Resources Ltd., Baytex Energy Ltd., Bonavista Energy Corp., Canadian Natural Resources Limited, Cenovus Energy Inc., ConocoPhillips Canada, Crescent Point Energy Corp., Crew Energy Inc., Delphi Energy Corp., Devon Canada, Enerplus Corporation, Harvest Operations Corp., Husky Oil Operations Limited, Legacy Oil & Gas Ltd., NAL Resources Limited, Northern Blizzard Resources Inc., Pace Oil & Gas Ltd., Pengrowth Energy Corporation, Penn West Petroleum Ltd., Perpetual Energy Inc., PetroBakken Energy Ltd., PotashCorp., The Mosaic Company, Rife, Sabre Energy Ltd., Talisman Energy Canada, Taqa North Ltd. and Vermilion Resources Ltd.

Over 90% 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 property 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 the most valuable category of Royalty Lands, because the rights 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 2012, this category of land accounted for 19% of our total royalty acreage and provided approximately 46% 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 535,435 acres, of which 80% are leased and 20% are unleased. The mineral title lands also include approximately 168,300 undeveloped acres, representing potential for further development. The majority of Freehold's mineral title lands are in areas south of the North Saskatchewan River, in the watershed of the Hudson Bay. 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 23.

Royalty Assumption Lands

The Corporation holds royalty interests in approximately 94,800 acres, of which approximately 20,900 acres are undeveloped. These lands consist of mineral title properties 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 and which, by their terms, are expressed to be interests in land. As the royalty interests with respect to the royalty assumption lands are a title royalty representing an interest in land, the royalties are held in perpetuity. In 2012, this category of land accounted for 3% of our total royalty acreage and provided approximately 3% of our royalty revenue.

Gross Overriding Royalty Lands

The Corporation holds gross overriding royalties in approximately 2,175,000 acres, of which approximately 603,500 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). 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 2012, this category of land accounted for 78% of our total royalty acreage and provided approximately 51% 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 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, 2012, and wells drilled, oil and natural gas production, and royalty revenue for 2012 for the Corporation's Royalty Lands:

Year ended December 31, 2012		Alberta West	Lloydminster	Saskatchewan East	Total
Average royalty interest ⁽¹⁾	(%)	1.4	4.4	0.8	1.6
Wells drilled	(gross)	185	119	127	431
Royalty income ⁽²⁾	(\$000s)	40,636	39,927	24,399	104,962
Average daily production	(boe/d)	3,373	1,894	996	6,263
Oil and NGL	(bbls/d)	1,180	1,640	795	3,615
Natural gas	(Mcf/d)	13,153	1,523	1,210	15,886
Net proved reserves	(Mboe)	6,889	3,298	1,907	12,095
Oil and NGL	(Mbbls)	2,021	2,880	1,345	6,246
Natural gas	(MMcf)	29,208	2,509	3,375	35,092
Net proved plus probable reserves	(Mboe)	10,481	5,659	2,877	19,017
Oil and NGL	(Mbbls)	3,267	4,952	2,040	10,259
Natural gas	(MMcf)	43,284	4,241	5,024	52,549
Future Net Revenue ⁽¹⁾⁽²⁾					
Discounted at 10% per year	(\$000s)	237,854	189,504	100,038	527,395
	(% of total)	45	36	19	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, as at December 31, 2012:

Area	Developed Acres	Undeveloped Acres ⁽¹⁾	Total Acres
Alberta West	1,358,131	337,137	1,695,268
Lloydminster	333,904	99,934	433,838
Saskatchewan East	304,994	348,372	653,366
Potash	15,515	7,351	22,866
Total	2,012,544	792,794	2,805,338

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

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 60% of Freehold's total royalty acreage, 54% of royalty production, and 55% of net proved plus probable reserves. In 2012, industry operators drilled 185 gross wells on the Royalty Lands in the region. On a boe basis, production increased 17% in 2012 and was 35% oil and NGL and 65% natural gas. The oil production is 95% light and medium quality crude.

The industry has continued to adopt the technology of drilling horizontal wells with multi-fracture stimulation to exploit low permeability reservoirs. In 2012, the Cardium was the primary target for operators on the Royalty Lands in this region, accounting for approximately 44% of the wells drilled.

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, 30% of royalty production, and 30% of net proved plus probable reserves. In 2012, industry operators drilled 119 gross wells on the Royalty Lands in the region. On a boe basis, production increased 2% in 2012 and was 87% oil and NGL (98% heavy) and 13% natural gas.

The primary target for operators on the Royalty Lands in Lloydminster area is Mannville heavy oil. The oil is exploited with vertical wells using CHOPS (cold heavy oil production with sand) technology or with horizontal wells.

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 23% of Freehold's total royalty acreage, 16% of royalty production, and 15% of net proved plus probable reserves. In 2012, industry operators drilled 127 gross wells on the Royalty Lands in the Saskatchewan East region. On a boe basis, production increased 17% in 2012 and was 80% oil and NGL and 20% natural gas.

In Saskatchewan and Manitoba, production is almost entirely light to medium oil production and is largely from the Paleozoic aged reservoirs of the Williston Basin.

Potash

In 1996, the Corporation acquired the right to the revenue from Canpar's lessor royalty interest in over 9,750 gross acres of leases issued to various operators of seven potash mines, all located within the Province of Saskatchewan. These leases are included within larger potash units, which cover the total mine areas. In 2005, the acquisition of the Partnership resulted in the Corporation increasing its mineral title ownership in six of these mines. As a result, the Corporation's potash acreage inventory increased to approximately 22,900 gross acres.

The potash mines from which the Corporation receives royalties are operated by Potash Corporation of Saskatchewan and The Mosaic Company. In 2012, the Corporation received revenue of approximately \$1.8 million from the production of approximately nine tonnes per day of potash. As the Corporation's minor interests in potash reserves are not material to the Corporation, the Manager has not obtained a recent independent evaluation of the potash reserves.

Undeveloped Royalty Lands

The undeveloped lands are lands without producing or potentially producing wells totalling 792,794 gross acres. Potential exists on these lands for drilling non-unitized zones within producing units, drilling or completing additional zones, infill drilling by downsizing the 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, 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 rights.

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 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. 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 1,054 unitized and non-unitized development wells were drilled. The number of oil wells drilled has increased while the number of natural gas wells drilled has decreased. No exploratory wells were drilled during this period. The drilling activity on the Royalty Lands in the last two fiscal years may not be indicative of future activity.

The drilling on the Royalty Lands in 2012 included the drilling and completion of 81 unitized and 143 non-unitized horizontal wells compared with 92 unitized and 142 non-unitized horizontal wells in 2011.

Years Ended December 31 ⁽¹⁾ (gross wells)	2012		2011	
	Unitized	Non-Unitized	Unitized	Non-Unitized
Oil wells	190	187	133	212
Natural gas wells	4	13	185	38
Service/other wells	6	29	4	50
Dry and abandoned wells	-	2	-	1
Total	200	231	322	301
Success rate	100%	99%	100%	100%

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

Reconciliation of Royalty Lands Reserves

The following table provides a summary of the changes in the net oil and natural gas reserves on our Royalty Lands during 2012, based on forecast prices and costs:

	Light and Medium Oil			Heavy Oil		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2011	1,988	1,041	3,028	3,841	2,293	6,135
Extensions	255	167	422	176	102	278
Improved recovery	-	-	-	-	-	-
Technical revisions	99	(64)	36	133	34	167
Discoveries	-	-	-	-	-	-
Acquisitions	83	29	111	12	25	37
Dispositions	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-
Production	(448)	-	(448)	(677)	-	(677)
December 31, 2012⁽¹⁾	1,977	1,173	3,150	3,485	2,454	5,940

	Natural Gas			Natural Gas Liquids		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2011	28,655	14,382	43,037	674	313	987
Extensions	778	499	1,277	42	27	69
Improved recovery	-	-	-	-	-	-
Technical revisions	181	(1,327)	(1,146)	33	(17)	15
Discoveries	-	-	-	-	-	-
Acquisitions	11,716	3,903	15,619	203	64	267
Dispositions	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-
Production	(6,239)	-	(6,239)	(168)	-	(168)
December 31, 2012⁽¹⁾	35,092	17,457	52,549	784	386	1,170

	Oil Equivalent		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2011	11,279	6,044	17,322
Extensions	603	379	982
Improved recovery	-	-	-
Technical revisions	295	(269)	27
Discoveries	-	-	-
Acquisitions	2,250	768	3,018
Dispositions	-	-	-
Economic factors	-	-	-
Production	(2,333)	-	(2,333)
December 31, 2012⁽¹⁾	12,095	6,922	19,017

(1) Columns may not add due to rounding.

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

Working Interest Properties

The Corporation owns working interests in 107 oil and natural gas properties. Production from these properties is comprised of approximately 80% oil and NGL and 20% natural gas. Working interest production averaged 2,587 boe per day in 2012, up from 1,898 boe per day in 2011. In 2012, 37 (14.1 net) wells were drilled, compared with 34 (11.6 net) wells during 2011.

In 2013, we expect to spend approximately \$30 million on development activities. Development plans are primarily oil related on the Corporation's mineral title lands and include approximately 40 gross (13 net) wells. Roughly half of our capital will be deployed in Southeast Saskatchewan (light oil), with the balance allocated to our expanding mineral title opportunity base in both the Lloydminster area (heavy oil) and western Alberta (Cardium oil).

Year ended December 31, 2012		Southeast Saskatchewan ⁽²⁾	Other (106 properties) ⁽²⁾	Total ⁽²⁾
Average working interest ⁽¹⁾	(%)	18.9	8.2	9.1
Wells drilled	(gross/net)	22/9.0	15/5.1	37/14.1
Net pre-tax operating income ⁽³⁾	(\$000s)	24,622	13,919	38,541
Average daily production	(boe/d)	1,148	1,439	2,587
Oil and NGL	(bbls/d)	1,079	1,001	2,080
Natural gas	(Mcf/d)	415	2,627	3,042
Net proved reserves	(Mboe)	378	2,609	2,988
Oil and NGL	(Mbbls)	364	2,016	2,380
Natural gas	(MMcf)	86	3,559	3,644
Net proved plus probable reserves	(Mboe)	905	4,503	5,408
Oil and NGL	(Mbbls)	871	3,470	4,342
Natural gas	(MMcf)	203	6,198	6,400
Future Net Revenue				
Discounted at 10% per year	(\$000s)	42,004	68,913	110,917
	(% of total)	38	62	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 royalty interests.
- (3) Excludes income from interest and other.
- (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 44% of working interest production and 17% of net proved plus probable reserves associated with our working interest properties. Our average working interest is 18.9%, which increased from 13.5% in 2011 due to our drilling program. In 2012, we participated in 22 (9.0 net) wells, primarily on the Corporation's mineral title lands. Capital expenditures totalled approximately \$26 million in 2012, and in 2013 we have allocated about half of our capital budget to this area.

In aggregate, from 2005 to 2012, we have participated in 107 (42.2 net) wells in Southeast Saskatchewan. Of these, 51 (23.8 net) were Bakken formation wells and the balance were various Mississippian zones. This participation is the result of the particularly favourable, oil based economics of these opportunities. Approximately 28,000 gross acres of the Corporation's Bakken mineral title lands are unleased.

Production in Southeast Saskatchewan increased 74% in 2012, and was 94% oil and NGL and 6% gas. All of the oil production is of light and medium quality.

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 ownership interests ranging from 20% to 50%.

Other Working Interest Properties

We own various working interests in 106 other properties, which accounted for 56% of the working interest production during 2012 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 per day to production. Capital expenditures totalled approximately \$11 million in 2012, and development activities included the drilling of 15 (5.1 net) wells. Production increased 16% in 2012 and was 70% oil and NGL and 30% natural gas.

In 2013 we have allocated about half of our capital budget to various other working interest properties, primarily on our mineral title lands in the Lloydminster area (heavy oil) and west central Alberta (Cardium light oil).

Working Interest Wells

The following table sets forth the number and status of wells as at December 31, 2012 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	189	41.1	-	-	25	2.6	-	-
Other (106 properties)	678	89.9	521	19.8	179	25.8	150	8.2
Total ⁽⁴⁾	867	131.0	521	19.8	204	28.3	150	8.2

(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 during the years ended December 31, 2012 and December 31, 2011. No exploratory wells were drilled during this period.

Years Ended December 31	2012		2011	
	Gross	Net	Gross	Net
Wells Drilled				
Oil wells	36	13.5	29	11.1
Natural gas wells	-	-	3	0.4
Service/other wells	-	-	2	0.1
Dry and abandoned wells	1	0.6	-	-
Total	37	14.1	34	11.6
Success rate	97%		100%	

Reconciliation of Working Interest Property Reserves

The following tables provide a summary of the changes in the gross oil and natural gas reserves on our working interest properties during 2012, based on forecast prices and costs:

	Light and Medium Oil			Heavy Oil		
	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2011	1,690	1,009	2,699	839	666	1,505
Extensions	391	324	715	186	121	306
Improved recovery	-	-	-	-	-	-
Technical revisions	278	(137)	141	52	(134)	(81)
Discoveries	-	-	-	-	-	-
Acquisitions	5	149	154	50	265	314
Dispositions	-	-	-	-	-	-
Economic factors	(1)	1	(1)	1	(2)	(1)
Production	(537)	-	(537)	(272)	-	(272)
December 31, 2012⁽¹⁾	1,826	1,346	3,173	856	916	1,771

	Natural Gas			Natural Gas Liquids		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbbls)	Probable (Mbbbls)	Proved Plus Probable (Mbbbls)
December 31, 2011	4,339	3,003	7,342	182	127	309
Extensions	35	28	63	-	-	-
Improved recovery	-	-	-	-	-	-
Technical revisions	756	(370)	386	7	(16)	(9)
Discoveries	-	-	-	-	-	-
Acquisitions	59	397	456	3	13	16
Dispositions	-	-	-	-	-	-
Economic factors	(39)	(16)	(55)	-	-	-
Production	(1,067)	-	(1,067)	(38)	-	(38)
December 31, 2012⁽¹⁾	4,083	3,042	7,125	154	124	277

	Oil Equivalent		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2011	3,434	2,303	5,736
Extensions	583	449	1,032
Improved recovery	-	-	-
Technical revisions	463	(348)	115
Discoveries	-	-	-
Acquisitions	68	493	560
Dispositions	-	-	-
Economic factors	(7)	(4)	(11)
Production	(1,024)	-	(1,024)
December 31, 2012⁽¹⁾	3,516	2,893	6,409

(1) Columns may not add due to rounding.

(2) 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.

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, 2012:

Working Interest Properties	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	635	72.1	149	15.7	302	15.6	132	6.7
Saskatchewan	216	57.8	46	12.4	2	0.4	4	1.4
British Columbia	4	0.1	9	0.3	217	3.9	14	0.1
Manitoba	12	0.9	-	-	-	-	-	-
Total ⁽¹⁾	867	131.0	204	28.3	521	19.8	150	8.2

(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	5,116	2,593	8,378	5,167
Saskatchewan	1,245	2,050	33	3,682
British Columbia	187	30	1	30
Manitoba	-	26	1	48
Ontario	161	0	-	-
Total ⁽¹⁾	6,709	4,699	8,413	8,927

(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, 2012:

	Undeveloped Acres		
	Royalty Lands	Working Interest Lands	
	Gross	Gross	Net
Alberta	380,780	26,695	5,480
Saskatchewan	199,025	7,427	4,417
British Columbia	26,571	6,131	101
Manitoba	1,584	-	-
Ontario	184,834	-	-
Total	792,794	40,253	9,998

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 2,962 gross acres.

Undeveloped lands are calculated by adding the surface area acreage covered by the leases or agreements or portions of the leases or agreement 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

Up until December 31, 2010, our trust structure was such that both current income tax and deferred tax liabilities were passed on to our unitholders. With our conversion from a trust to a corporation, we became subject to normal corporate tax rates starting in 2011. The corporate income tax rate applicable to the 2011 tax year was 26.9%. In 2012, we paid minimal income tax relating to the 2011 tax year (\$2.3 million) due to the tax deductions available to us and the effect of the deferral of our partnership income.

In December 2011, legislation was passed implementing tax measures outlined in the 2011 budget (Bill C-13), which included the elimination of the ability of a corporation to defer income as a result of timing differences in the year-end of the corporation and of any partnership of which it is a member, subject to transitional relief over five years. Freehold's deferred income tax liability includes a partnership deferral that will be reduced over the transitional relief period.

The corporate income tax rate applicable to 2012 is approximately 25%. 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. In February 2013, we paid \$23 million for estimated 2012 corporate taxes. For the 2013 tax year, we expect to pay approximately \$25 million by way of monthly instalments. We expect our tax bill will normalize in 2014, at approximately 20% of pre-tax cash flow.

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 Corporation did not have any exploration costs related to its activities for the year ended December 31, 2012.

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, 2012. The acquisition costs were for Royalty Lands and working interest properties. The development costs were on our working interest or unleased mineral title lands.

	(\$000s)
Property acquisition costs ⁽¹⁾	
Proved properties	51,338
Undeveloped/unproved properties	9,514
Development costs	36,746
Total	97,598

(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, 2012 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 fields account for more than 20% of the production estimate.

Reserves Category	Light and Medium Oil		Heavy Oil		Total Crude Oil	
	Gross ⁽¹⁾ (bbls/d)	Net (bbls/d)	Gross ⁽¹⁾ (bbls/d)	Net (bbls/d)	Gross ⁽¹⁾ (bbls/d)	Net (bbls/d)
Proved						
Developed producing	1,023	1,817	697	2,092	1,721	3,909
Developed non-producing	-	-	-	3	-	3
Undeveloped	-	-	35	28	35	28
Total proved	1,023	1,817	732	2,123	1,755	3,940
Probable	339	408	184	264	523	672
Total proved plus probable ⁽²⁾	1,363	2,225	916	2,387	2,279	4,612
	Natural Gas		Natural Gas Liquids		Oil Equivalent	
Reserves Category	Gross ⁽¹⁾ (Mcf/d)	Net (Mcf/d)	Gross ⁽¹⁾ (bbls/d)	Net (bbls/d)	Gross ⁽¹⁾ (boe/d)	Net (boe/d)
Proved						
Developed producing	2,212	15,513	72	405	2,162	6,899
Developed non-producing	-	262	-	1	-	48
Undeveloped	-	-	-	-	35	28
Total proved	2,212	15,774	72	405	2,196	6,975
Probable	348	1,231	11	34	592	911
Total proved plus probable ⁽²⁾	2,561	17,006	83	440	2,789	7,886

(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 Corporation is unique in that the majority of our 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:

	2012				2011			
	Quarter Ended				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 Oil (bbls/d)	3,388	3,160	2,605	2,860	2,644	2,177	2,092	2,289
Heavy Oil (bbls/d)	2,363	2,159	2,354	2,242	2,079	1,865	2,050	2,237
Natural Gas (Mcf/d)	20,420	17,110	18,642	19,541	16,150	16,751	17,917	15,872
NGL (bbls/d)	355	483	435	374	358	361	317	318
Combined (boe/d)	9,510	8,654	8,501	8,733	7,773	7,195	7,445	7,490
Average price realized								
Light and Medium Oil (\$/bbl)	80.12	80.09	77.24	87.84	91.27	84.52	94.07	81.46
Heavy Oil (\$/bbl)	61.33	63.59	60.42	73.34	78.78	64.03	73.47	61.79
Natural Gas (\$/Mcf)	2.56	1.73	1.15	2.06	2.91	3.15	3.36	3.05
NGL (\$/bbl)	60.92	56.96	55.27	60.40	81.06	65.42	67.19	63.32
Combined (\$/boe)	51.55	51.71	45.74	54.80	61.90	52.80	57.61	52.51
Royalty expense ⁽²⁾								
Light and Medium Oil (\$/bbl)	4.94	3.45	5.09	2.74	2.36	2.92	2.92	2.20
Heavy Oil (\$/bbl)	1.48	2.10	1.52	2.19	1.70	2.06	1.88	2.23
Natural Gas (\$/Mcf)	-	(0.01)	0.03	0.01	0.03	0.08	-	(0.06)
NGL (\$/bbl)	2.70	2.48	1.87	4.12	4.22	4.29	3.09	3.20
Combined (\$/boe)	2.24	1.91	2.15	1.67	1.52	1.82	1.47	1.35
Operating expenses (\$/boe) ⁽³⁾								
Light and Medium Oil (\$/bbl)	7.98	7.09	6.05	7.84	7.93	8.79	8.31	5.04
Heavy Oil (\$/bbl)	8.57	7.58	5.51	6.86	7.11	8.51	6.08	6.03
Natural Gas (\$/Mcf)	0.22	0.23	0.21	0.13	0.27	0.19	0.20	0.04
NGL (\$/bbl)	1.97	1.57	2.16	1.35	2.62	2.16	2.10	0.37
Combined (\$/boe)	5.51	5.02	3.96	4.68	5.28	5.43	4.57	3.44
Netback received ⁽⁴⁾								
Light and Medium Oil (\$/bbl)	67.20	69.55	66.10	77.26	80.98	72.81	82.84	74.22
Heavy Oil (\$/bbl)	51.28	53.91	53.39	64.29	69.97	53.46	65.51	53.53
Natural Gas (\$/Mcf)	2.34	1.51	0.91	1.92	2.61	2.88	3.16	3.07
NGL (\$/bbl)	56.27	52.91	51.24	54.95	74.22	58.97	62.00	59.75
Combined (\$/boe)	43.80	44.78	39.63	48.45	55.10	45.55	51.57	47.72

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

(3) 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.

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

(5) 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, 2012:

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (boe/d)
Royalty Lands ⁽¹⁾					
Alberta West	840	48	13,153	292	3,373
Lloydminster	25	1,612	1,523	3	1,894
Saskatchewan East	776	1	1,210	18	996
Working Interest Properties ⁽²⁾					
Southeast Saskatchewan	1,036	-	415	43	1,148
Other (106 properties)	344	602	2,627	55	1,439
Total	3,021	2,263	18,928	411	8,850

(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).

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.

Almost 90% of Freehold's royalty revenue comes from 30 oil and gas companies. The majority 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 on our Royalty Lands as these are the responsibility of the working interest owners. Ongoing environmental obligations are funded from funds from operations. At December 31, 2012, our estimated undiscounted share of future environmental and reclamation obligations for the working interest properties was approximately \$28.0 million.

Future abandonment and reclamation costs have been estimated based on actual costs incurred to date for abandonment and reclamation activities. In the future, we expect to abandon and reclaim approximately 230 net wells at the estimated costs identified in the following table:

As at December 31, 2012	Abandonment and Reclamation Costs (Net of Salvage Value) (\$000s)	
	Undiscounted	Discounted at 10%
Total costs as at December 31, 2012	28,028	6,474
Total costs not deducted from future net revenue	18,367	2,927
Expected to be paid in 2013	596	568
Expected to be paid in 2014	651	564
Expected to be paid in 2015	207	163

BORROWINGS

Freehold has a \$195 million extendible revolving term credit facility with a syndicate of three Canadian chartered banks and a \$15 million extendible revolving operating facility. Borrowings under the facilities bear interest at the bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins and standby fees. The facilities are secured with \$300 million demand debentures over Freehold's petroleum and natural gas assets but do not contain any financial covenants. As at December 31, 2012, we had \$192 million of available capacity under our credit facilities.

Freehold's borrowing base is dependent on our lenders' annual review and interpretation of our reserves and future commodity prices. This review was completed in the second quarter of 2012 with no changes to our borrowing base. 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.

Under our credit facilities, we are restricted from making 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, 2012, Freehold was in compliance with all such covenants.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia, Saskatchewan and Manitoba, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

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

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX) or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can be set by such supply and demand. Natural gas

exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

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

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

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern 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 other than Crown lands 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.

Alberta

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

Royalties are currently paid pursuant to “The New Royalty Framework” (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the “Alberta Royalty Framework”, which was implemented in 2010.

Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than \$535/m³ compared to the previous royalty curve.

Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than \$5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1%-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil and 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 1%-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above \$55 up to 40% when oil is priced at \$120 or higher. In addition, concurrently with the implementation of the New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the current royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

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

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008 with the intention to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a \$1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to \$3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of \$875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells between 1,000 and 3,500 metres receive a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. Production from wells operating under the transitional royalty rates will not be subject to the royalty curves for conventional oil and natural gas.

On March 17, 2011, the Government of Alberta approved the *New Well Royalty Regulation* providing for the permanent implementation of a formerly temporary royalty program which provides for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated "volume cap" is reached.

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

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

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. 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 based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (“**old oil**”), between October 31, 1975 and June 1, 1998 (“**new oil**”), or after June 1, 1998 or through an Enhanced Oil Recovery (“**EOR**”) Scheme (“**third-tier oil**”). 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 the 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 level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to oil production on Crown land. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The freehold production tax rate for natural gas liquids is a flat 12.25%.

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

- *Summer Royalty Credit Program* providing a royalty credit equal to 10% of the goods and services costs up to \$100,000 for wells drilled between April 1 and November 30 of each year;
- *Deep Royalty Credit Program* providing a royalty credit 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 2,300 metres (or 1,900 metres if spud after August 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs that relate to locations specific factors;

- *Deep Re-Entry Royalty Credit Program* providing royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres and a re-entry date subsequent to December 1, 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;
- *Natural Gas Royalty Reduction* providing a reduced royalty on wells drilled on land rights acquired after June 1, 1998 and completed within 5 years of the date the rights are issued;
- *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 monthly royalty reductions for low productivity non-conservation natural gas wells with average monthly production under 25,000 m³ during the first 12 production months and average daily production less than 23 m³ for every metre of marginal well depth;
- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow non-conservation natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m³ during the first 12 production months and average daily production less than 11.0 m³ (development wells) or 17 m³ (exploratory wildcat wells) for every 100 metres of marginal well depth; and
- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m³ of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the “**Infrastructure Royalty Credit Program**”) which 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.

In August 2012, the Government of British Columbia announced that it is bringing in a nominal 2% royalty on both oil and natural gas on the revenue for the first year of production for wells drilled from September 2012 through to June 2013.

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into “types”, being “heavy oil”, “southwest designated oil” or “non-heavy oil other than southwest designated oil”. The conventional royalty and production tax classifications (“fourth tier oil”, “third tier oil”, “new oil” and “old oil”) depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects) or new oil (oil from wells drilled on or after January 1, 1994). Southwest designated oil uses the same definitions of third and fourth tier oil but 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 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, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the “Production Tax Factor” (“**PTF**”) applicable to that classification of oil. Currently the

PTF is 6.9 for “old oil”, 10.0 for “new oil” and “third tier oil” and 12.5 for “fourth tier oil”. The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m³ for “old oil”, “new oil” and “third tier oil”, and 250 m³ per month for “fourth tier oil”. Where average wellhead prices are below the established base prices of \$100 per m³ for third and fourth tier oil and \$50 per m³ for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as “non-associated gas” (gas produced from gas wells) or “associated gas” (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 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. Natural gas liquids and by-products recovered at gas processing plants are not subject to a royalty. Gas liquids which are produced and measured at the wellhead are treated as crude oil for royalty purposes.

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

As with conventional oil production, base prices based on a well reference rate of 250 10³ m³/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of \$50 per thousand m³ for third and fourth tier gas and \$35 per thousand m³ for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas. The current regulatory scheme provides for certain differences with respect to the administration of “fourth tier gas” which is associated gas.

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

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of “fourth tier oil” Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m³ for deep development vertical oil wells, 4,000 m³ for non-deep exploratory vertical oil wells and 16,000 m³ for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the “fourth tier” royalty tax rate;
- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of “fourth tier oil” Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m³ for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of “fourth tier oil” Crown royalty rate and 2.5%) and freehold tax rates 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 or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the “fourth tier” royalty tax rate;
- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of “fourth tier oil” Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m³ for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the “fourth tier” royalty tax rate;
- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% of EOR operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR projects; and
- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting “third tier oil” royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

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

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

Manitoba

In Manitoba, 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 from the Minister. 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 per 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 ten (10) years of the finished drilling date or the completion date of a major workover. Wells drilled for injection, or converted to injection wells, in an approved enhanced recovery project, earn one (1) year holiday for portions of the project area. Under the Program, wells drilled for purposes of injection (or wells converted to injection prior to producing predetermined volumes of oil) in an approved enhanced oil 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:

- *New Well Incentive* provides licensees of newly drilled, non-horizontal wells drilled prior to January 1, 2014 with a holiday oil volume to a maximum of 10,000 m³;
- *Deep Drilling Incentive* provides licensees who drill a well to a total depth sufficient to penetrate the Devonian Duperow formation with a holiday oil volume of up to 20,000 m³, and licensees who drill a well deeper than the Devonian Three Forks formation can make a one-time assignment of up to 10,000 m³ of holiday oil volume earned through previous drilling or major workovers to such well's holiday oil volume;
- *Horizontal Well Initiative* provides licensees of horizontal wells drilled prior to January 1, 2014 with a holiday oil volume of 10,000 m³, and the first horizontal leg (unless otherwise approved) drilled from an existing horizontal well on or after January 1, 2009 and prior to January 1, 2014 and more than one (1) year after the finished drilling date of the well), will earn an additional holiday royalty volume of 3,000 m³;
- *Marginal Well Major Workover Incentive* provides licensees of marginal wells where a major workover is completed prior to January 1, 2014 with a holiday oil volume of 500 m³, with a marginal oil well defined as an abandoned well or a well that was either not operated over the previous 12 months or produced oil at an average rate of less than 1 m³ per operating day; and
- *Injection Well Incentive* provides a one year exemption from the payment of Crown royalties or freehold production taxes on production allocated to a unit tract in which a well is drilled or converted to water injection;

Further, holiday oil volumes earned by a newly drilled well or a marginal well that has undergone a major workover can be transferred to a Holiday Oil Volume Account at the request of the licensee, the purpose of which is to optimize the value of holiday oil volumes earned by providing a company with the flexibility of allocating holiday oil volumes earned among new wells.

Land Tenure

The respective provincial governments predominantly own crude oil and natural gas located in the western provinces, with the exception of Manitoba, where private ownership accounts for approximately 80% of 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 has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia expanded its policy of deep rights reversion for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their 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 licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will

receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences granted prior to January 1, 2009, but continued after that date, are not subject to shallow rights reversion until they continue past their primary term (at which time the application of deep rights reversion occurs). Afterwards, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements for the satisfactory 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 licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

On a Federal level and pursuant the Prosperity Act, the Government of Canada amended or appealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime. The changes to the environmental legislation under the Prosperity Act are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

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 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.

The *Alberta Land Stewardship Act* (the “ALSA”) was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be 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, leases, licenses, 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 effect on September 1, 2012. The LARP covers approximately 93,212 square kilometres and is in the northeast corner of Alberta. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% cent of the provinces oil sands resource and much of the Cold Lake oil sands area. LARP establishes six new conservation areas, bringing the total conserved land in the region to two million hectares, or 22% – an area three times the size of Banff National Park. The Alberta government plans to pay \$30 million to producers whose leases will be cancelled in areas set aside for conservation. Oil and gas companies will be allowed to continue to operate in conservation and recreation areas while oil sands companies' tenures will be cancelled. New petroleum and gas tenure sold in conservation areas will include a restriction that prohibits surface access. Application procedures for activities and facilities in the LARP, regulated by the Energy Resources Conservation Board and the Alberta Utilities Commission, respectively, have been changed to accommodate the new restrictions set out in the LARP. The LARP is the first of seven regions to get a land use plan. The next will be the South Saskatchewan region.

In British Columbia, the *Oil and Gas Activities Act* (the “**OGCA**”) impacts conventional oil and gas producers, shale gas producers, and other operators of oil and gas facilities in British Columbia. Under the OGCA, the British Columbia Oil and Gas 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 OGCA requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act* requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, and permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole, and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

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

Climate Change Regulation

Federal

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 greenhouse gases (“**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, which will be applied to regulated sectors on a facility-specific, a sector-wide or a company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets. Although the intention was for draft regulations for the implementation of the Updated Action Plan to become binding on January 1, 2010, the only regulations announced pertain to carbon dioxide emissions from coal-fired generation of electricity (finalized in summer 2012). Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent implementation of the proposals contained in the Updated Action Plan will occur.

The United States Environmental Protection Agency (the “**EPA**”) has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it would issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline. However, in March 2012, the EPA proposed a strict GHG standard on new power plants only. While it is expected that this rule could encourage building new natural gas power plants rather than coal plants, the actual effect of the new rule will not be able to be quantified for some time.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the “**CCEMA**”) on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between “Established Facilities” and “New Facilities”. Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of \$15 per tonne of CO₂ equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

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

In February 2008, 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 CO₂ equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, 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.

In their 2012 Budget, British Columbia announced the government will undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review will cover all aspects of the carbon tax, including revenue neutrality, and will consider the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia’s food producers. Under this comprehensive review, British Columbians can make written submissions to British Columbia’s Minister of Finance, and these will be considered as part of the 2013 Budget process.

On April 3, 2008, 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 Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. The Cap and Trade Act sets out the requirements for the reporting of the greenhouse gas 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. Recent amendments to the Act repealed past requirements on public-

sector organizations, including Crown corporations, to be carbon neutral by 2010, and they are now only required to produce annual carbon reduction plans and reports. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under further development.

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. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020.

Manitoba

The Government of Manitoba has commenced public consultations with respect to the development of a cap and trade system to reduce GHG emissions; however, no legislation is currently in effect in Manitoba. In June 2007, Manitoba joined the Western Climate Initiative (“**WCI**”), which was established to identify, evaluate and implement collective, co-operative ways to reduce greenhouse gases within a specified region. The regional partners who form the WCI focus on a market based cap and trade system, and additional reduction opportunities through complementary measures. WCI regional partners include seven U.S. states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington) and four Canadian provinces (British Columbia, Manitoba, Ontario and Québec). The WCI's goal is to reduce GHG emissions in the region by 15% below 2005 levels, by 2020. When fully implemented in 2015, the WCI aims to cover nearly 90% of the region's emissions.

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, nor should 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.

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 to explore and develop its existing properties and on 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 participations uneconomic. There is also no assurance that the Corporation 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 assure 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, and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect 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, and spills or 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.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by OPEC and the ongoing global credit and liquidity concerns. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable 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 or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Deliverability uncertainties related to the distance the Corporation's reserves are to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and 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 conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply 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 ability to access such markets. 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 of the Corporation's reserves. The Corporation 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 acquisition, 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, and sanctions imposed on certain oil producing nations by other countries, and the 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 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.

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. 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 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.

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.

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 and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;

- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, 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 and Pipeline Systems

The Corporation delivers its products through gathering, processing and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

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 materially adversely affect the Corporation's ability to process its production and to deliver the same for sale.

Competition

The petroleum industry is competitive in all 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. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. 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 oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before 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. 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 materially adversely affected. If the Corporation is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could be materially adversely affected.

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 and other 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 (exploration, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of 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 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 will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt a new or modify the royalty regime, which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. Specifically, hydraulic fracturing is used to produce 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 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 is 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 spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

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 regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and which may require the Corporation to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "UNFCCC") and as 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 will seek a 17% reduction in greenhouse gas ("GHG") emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Although it is not the case today, 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. 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. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition.

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. Recently, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively affect the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly affect the future value of the Corporation's reserves as determined by independent evaluators.

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 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);
- 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. 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 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. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Corporation's access to additional financing may be affected.

Because of the global economic 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. 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 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 the default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, 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. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. 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. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility which could result in the requirement to repay a portion, or all, of the Corporation's bank 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

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 in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, 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) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

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 an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim. The actual interest of the Corporation in properties may, therefore, 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 proposed legislative changes which affect title, to the oil and natural gas properties the Corporation controls that, if successful or made into law, could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas, natural gas liquids, and sulphur 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 therefrom are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of 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 thereof and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar 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 thus does not reflect changes in the Corporation's reserves since that date.

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 continue to 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 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 subject to 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

A portion of the Corporation's 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 fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by 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, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to 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.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to 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.

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 this 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 our 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. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation as the demand for natural gas rises during cold winter months and hot summer months.

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 the event such entities fail to meet their contractual 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 impact 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.

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 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 "Directors and Officers – 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 oil and gas production, exploration and development 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.

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 66,406,894 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 and low 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)			
	High	Low	Close	Volume Traded
2012				
January	20.96	19.16	20.81	1,922,853
February	21.59	20.25	20.53	3,430,673
March	20.57	19.46	19.59	2,722,857
April	19.67	17.91	18.90	3,382,563
May	19.33	17.64	17.79	2,044,966
June	18.91	17.25	18.44	2,055,378
July	19.97	17.83	19.42	1,536,777
August	19.70	19.00	19.61	1,870,954
September	20.34	19.23	19.76	2,247,962
October	20.59	19.62	20.28	2,519,099
November	21.48	20.03	21.09	2,356,293
December	22.45	20.91	22.40	2,559,395
2013				
January	24.48	21.97	23.10	2,398,141
February	23.68	21.00	21.00	2,440,239
March 1 to 6	22.43	21.21	22.18	721,905

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, 2012, our legal stated capital was \$389 million.

Upon completion of the Arrangement, Freehold commenced paying a monthly dividend to Shareholders initially set at \$0.14 per Common Share, which was equal to the monthly cash distribution paid to holders of Trust Units immediately prior to completion of the Arrangement. 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 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 Distributions and Dividends

Since January 1, 2013, Freehold has declared cash dividends of \$0.14 per Common Share for Shareholders of record on January 31, 2013, February 28, 2013, and March 31, 2013, payable on February 15, 2013, March 15, 2013, and April 15, 2013, respectively.

The tables below sets forth the amount of cash distributions the Trust paid on the Trust Units for the one year prior to completion of the Arrangement and the amount of cash dividends paid on the Common Shares during the two most recently completed financial years:

Record Date	Payment Date	Cdn\$ per Trust Unit
2010		
January 31, 2010	February 15, 2010	0.14
February 28, 2010	March 15, 2010	0.14
March 31, 2010	April 15, 2010	0.14
April 30, 2010	May 16, 2010	0.14
May 31, 2010	June 15, 2010	0.14
June 30, 2010	July 15, 2010	0.14
July 31, 2010	August 15, 2010	0.14
August 31, 2010	September 15, 2010	0.14
September 30, 2010	October 17, 2010	0.14
October 31, 2010	November 15, 2010	0.14
November 30, 2010	December 15, 2010	0.14
December 31, 2010	January 17, 2011	0.14
		1.68

Record Date	Payment Date	Cdn\$ per Share
2011		
January 31, 2011	February 15, 2011	0.14
February 28, 2011	March 15, 2011	0.14
March 31, 2011	April 15, 2011	0.14
April 30, 2011	May 16, 2011	0.14
May 31, 2011	June 15, 2011	0.14
June 30, 2011	July 15, 2011	0.14
July 31, 2011	August 15, 2011	0.14
August 31, 2011	September 15, 2011	0.14
September 30, 2011	October 17, 2011	0.14
October 31, 2011	November 15, 2011	0.14
November 30, 2011	December 15, 2011	0.14
December 31, 2011	January 16, 2012	0.14
		1.68

Record Date	Payment Date	Cdn\$ per Share
2012		
January 31, 2012	February 15, 2012	0.14
February 29, 2012	March 15, 2012	0.14
March 31, 2012	April 16, 2012	0.14
April 30, 2012	May 15, 2012	0.14
May 31, 2012	June 15, 2012	0.14
June 30, 2012	July 16, 2012	0.14
July 31, 2012	August 15, 2012	0.14
August 31, 2012	September 17, 2012	0.14
September 30, 2012	October 15, 2012	0.14
October 31, 2012	November 15, 2012	0.14
November 30, 2012	December 17, 2012	0.14
December 31, 2012	January 15, 2013	0.14
		1.68

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 DRIP became effective pursuant to the Arrangement to replace the cash distribution reinvestment plan of the Trust. 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.

Under the DRIP, we are currently issuing Common Shares from treasury instead of purchasing them in the market.

Effective with the May 15, 2011 dividend payment, the DRIP was amended and restated to allow for the issuance of 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).

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, Freehold Resources 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 26% of the outstanding Common Shares and as a result has the right to nominate two individuals as directors of Freehold. The number of directors of the Corporation is presently set at eight.

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 (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

The Board of Directors is currently comprised of eight individuals. The name, province of residence, position held and principal occupation of each director of Freehold are set out below:

Name and Province of Residence	Position with Freehold	Principal Occupation	Director Since
D. Nolan Blades ⁽³⁾ Alberta, Canada	Chair of the Board and Director	President, Sunny Gables Holdings Ltd. (private holding company)	July 29, 1996 ⁽⁶⁾
Harry S. Campbell, Q.C. ⁽³⁾⁽⁴⁾ Alberta, Canada	Director	Chairman, Burnet, Duckworth & Palmer LLP (barristers and solicitors)	July 29, 1996 ⁽⁶⁾
Peter T. Harrison ⁽⁴⁾⁽⁵⁾ Quebec, Canada	Director	Manager, Oil and Gas Investments CN Investment Division	July 29, 1996 ⁽⁶⁾
Arthur N. Korpach ⁽¹⁾⁽²⁾ Alberta, Canada	Director	Corporate Director	May 9, 2012
William O. Ingram ⁽⁵⁾ Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer, Rife (private oil and gas exploration and production company)	May 13, 2009 ⁽⁶⁾
P. Michael Maher ⁽¹⁾⁽³⁾ Alberta, Canada	Director	Professor, Haskayne School of Business University of Calgary	July 29, 1996 ⁽⁶⁾
David J. Sandmeyer ⁽²⁾⁽⁴⁾ Alberta, Canada	Director	Corporate Director	July 29, 1996 ⁽⁶⁾
Rodger A. Tourigny ⁽¹⁾⁽²⁾ Alberta, Canada	Director	President, Tourigny Management Ltd.	November 10, 2009 ⁽⁶⁾

(1) Member of Audit Committee.

(2) Member of Compensation Committee.

(3) Member of Governance and Nominating Committee.

(4) Member of Reserves Committee.

(5) Directors nominated for election at the last annual meeting of Shareholders held on May 12, 2012 by the Manager pursuant to the Governance Agreement.

(6) Reflects the date of election or appointment as a member of the board of directors of Freehold Resources.

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
William O. Ingram Alberta, Canada	President and Chief Executive Officer	President and Chief Executive Officer of Rife	July 29, 1996 ⁽¹⁾
Thomas J. Mullane Alberta, Canada	Executive Vice-President and Chief Operating Officer	Executive Vice-President and Chief Operating 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⁾
Garry W. Bieber Alberta, Canada	Vice-President, Production	Vice-President, Production of Rife	August 13, 2008 ⁽¹⁾
J. Frank George Alberta, Canada	Vice-President, Exploration	Vice-President, Exploration of Rife	July 29, 1996 ⁽¹⁾
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	Manager, Investor Relations and Corporate Secretary	Manager, Investor Relations and Corporate Secretary of Rife	February 27, 2008 ⁽¹⁾

(1) Reflects the date of appointment as an officer of Freehold Resources.

Each of the directors and officers of Freehold has been engaged in his principal occupation or in other capacities with the same firm or organization for the past five years except for Mr. Mullane who prior to joining Rife in 2012 was Senior Vice President of Bonavista Energy Corporation, Mr. Korpach who prior to May 31, 2012 was Vice-Chairman, Investment Banking at CIBC World Markets Inc., Mr. Harrison who prior to joining the CN Investment Division on August 24, 2009 was Senior Vice-President of Montrusco Bolton Investments Inc.; Mr. Sandmeyer, who retired as President and Chief Executive Officer of Freehold Resources, Rife and Canpar on May 13, 2009; and Mr. Stone, who prior to joining Rife in 2008 was Vice-President, Land with Real Resources Ltd.

As at March 7, 2013, the directors and senior officers of Freehold, as a group, beneficially owned or controlled, directly or indirectly, 105,971 Common Shares or less than 1% of the issued and outstanding Common Shares. CN Pension Trust Funds, owned, directly or indirectly, 17,464,958 Common Shares (approximately 26%) of the Corporation as at March 7, 2013. The Manager has received 1,917,850 Common Shares (including Common Shares issued pursuant to the Arrangement in exchange for Trust Units received by the Manager as payment of the Management Fee) in payment of the Management Fee to March 7, 2013.

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

D. Nolan Blades

Mr. Blades is President of Sunny Gables Holdings Ltd. (Calgary), a private investment company. Mr. Blades has obtained significant financial experience and exposure to accounting, financial and compensation issues as President and Chief Executive Officer of Pursuit Resources Corp. (1993 – 2000), prior to which he held senior executive positions with Chauvco Resources Ltd. and Oakwood Petroleums Limited. Mr. Blades has a Bachelor of Science degree in Mechanical Engineering and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

William O. Ingram

Mr. Ingram is President and Chief Executive Officer of the Corporation. He joined Rife (Calgary) in 1984 and was appointed President and Chief Executive Officer of Freehold Resources and Rife effective May 13, 2009. Previously, he was Executive Vice-President and Chief Operating Officer, which appointment was effective August 13, 2008. Prior to that, he was Vice-President, Production and was responsible for production and drilling operations, marketing, acquisitions, reserve analysis and economic evaluations. Mr. Ingram has a Bachelor of Science degree in Chemical Engineering from the University of Alberta and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Harry S. Campbell, Q.C.

Mr. Campbell is Chairman of the law firm Burnet, Duckworth & Palmer LLP (Calgary). He was admitted to the Alberta Bar in 1974 and has extensive experience with Canadian oil and gas transactions and international petroleum and natural gas matters. Mr. Campbell is a director of Delphi Energy Corp. and EmberClear Corp.

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. Mr. Harrison is chair of the board of directors of Pace Oil & Gas Ltd.

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. He has a Bachelor of Commerce degree from the University of Saskatchewan and an MBA from Harvard Business School. Mr. Korpach is chair of the board of directors of the United Way of Calgary and Area and a director of Canexus Corporation. He is a past chair of the Accounting Standards Board of the Canadian Institute of Chartered Accountants and a past director of Mount Royal University and its Foundation.

P. Michael Maher

Dr. Maher is a Professor and former Dean of the Haskayne School of Business, University of Calgary. Dr. Maher has conducted and published research on various aspects of corporate governance and the audit function. He has a Bachelor of Science degree in Engineering from the University of Saskatchewan, an MBA from the University of Western Ontario, a Ph.D. from Northwestern University, a Doctor of Commerce (honoris causa) degree from St. Mary's University and is a Professional Engineer.

David. J. Sandmeyer

Mr. Sandmeyer is a retired businessman and was formerly President and Chief Executive Officer of Freehold Resources and Rife until his retirement on May 13, 2009. Prior to joining Rife in 1982, he held senior positions with Amoco Canada Petroleum Company Ltd. A graduate of the University of Saskatchewan, he has a Bachelor of Science degree in Mechanical Engineering and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Mr. Sandmeyer is a director of Anderson Energy Ltd. and Delphi Energy Corp.

Rodger A. Tourigny

Mr. Tourigny is President of Tourigny Management Ltd. (Calgary), a private consulting company providing services to the oil and gas, financial services and real estate sectors since 1979. He has extensive financial experience in the oil and gas industry. He has a Bachelor of Commerce degree from the University of Saskatchewan and is a Chartered Accountant. Mr. Tourigny is a director of LED Medical Diagnostics Inc.

Thomas J. Mullane

Mr. Mullane joined Rife as Executive Vice-President and Chief Operating Officer on July 18, 2012. He has over 25 years of industry experience and a broad background in exploitation and production engineering gathered from both domestic and international assignments. 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).

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 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 General Accountant.

Garry W. Bieber

Mr. Bieber is Vice-President, Production of the Corporation and was appointed Vice-President, Production of Freehold Resources and Rife effective August 13, 2008. Mr. Bieber joined Rife in 1985 as Chief Engineer and has been Manager of Production since 1991. He is responsible for Environment, Health and Safety, production and drilling operations, and economic evaluations. Mr. Bieber has a Bachelor of Science degree in Geological Engineering from the University of Saskatchewan and is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

J. Frank George

Mr. George is Vice-President, Exploration of the Corporation and was appointed Vice-President, Exploration of Freehold Resources and Rife effective July 29, 1996. Mr. George joined Rife in 1983 as Chief Geologist and became Vice-President, Exploration of Rife effective September 23, 1996. He is responsible for the management and coordination of all exploration and geological evaluation activities of Rife. A graduate of the University of Calgary, Mr. George is a registered Professional Geologist in Alberta and a member of the Canadian Society of Petroleum Geologists.

Michael J. Stone

Mr. Stone, Vice-President, Land of the Corporation, began his association with Rife in 2008 as a consultant becoming Manager, Land Negotiations – Business Development and then General Manager, Land in 2009. Mr. Stone's appointment as Vice President, Land of Freehold Resources and Rife was effective March 1, 2010. 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.

Michael J. Mogan

Mr. Mogan, Controller of the Corporation, was appointed Controller of Freehold Resources effective August 13, 2008. Mr. Mogan joined Rife in 2003 as a Senior Accountant and was most recently the Manager of Financial Accounting. He is a Certified Management Accountant.

Karen C. Taylor

Ms. Taylor, Manager, Investor Relations and Corporate Secretary of the Corporation, joined Rife in February 1997 as Manager, Corporate Communications. Her appointment as Corporate Secretary of Freehold Resources and Rife was effective February 27, 2008. Ms. Taylor is a member of the Canadian Investor Relations Institute and the Canadian Society of Corporate Secretaries.

Corporate Cease Trade Orders or Bankruptcies

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. Except as described below, 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.

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. Rodger Tourigny (Chair), Mr. Arthur Korpach and Dr. P. Michael Maher. 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

	Year Ended December 31	
	2012	2011
Audit fees ⁽¹⁾	281,000	155,000
Audit-related fees ⁽²⁾	35,000	55,000
Tax fees ⁽³⁾	22,330	105,075
All other fees	-	-
Total	338,330	315,075

- (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.
- (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 include corporate conversion review work and advisory services relating to International Financial Reporting Standards (IFRS).
- (3) Tax fees consist of fees for tax compliance and advisory services. The services provided in this category included assistance and advice in relation to Shareholder taxation issues, review of corporate income tax returns and corporate conversion advisory.

THE MANAGER**Business of the Manager**

The Manager was established to provide comprehensive oil and gas company management and operational services to the Trust prior to completion of the Arrangement, and the Manager began providing such services to Freehold, Freehold Resources, and the Partnership upon completion of the Arrangement. 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, Freehold Resources and the Partnership.

Employees

Freehold has no employees but rather is managed by the Manager pursuant to the Management Agreement. On December 31, 2012, Rife had 89 full and part-time employees in the Calgary office and 15 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 Arrangement, Freehold, Freehold Resources and the Partnership entered into the Management Agreement with the Manager, pursuant to which Freehold, Freehold Resources and the Partnership engaged the Manager to:

- a. 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, Freehold Resources 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;
- b. provide management services for the economic and efficient exploitation of oil and natural gas properties;
- c. 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;

- d. recommend, carry out and monitor property acquisitions and dispositions and exploitation and development programs for Freehold and its subsidiaries and partnerships;
- e. negotiate on behalf of Freehold and its subsidiaries and partnerships all exploitation and development agreements, operating agreements, working agreements, farm in and farm out agreements, leases and other documents relating to the exploitation of the oil and natural gas properties as may be advisable;
- f. recommend and negotiate banking arrangements for Freehold; and
- g. 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 is renewed every three years for three year terms unless the termination of the Management Agreement at the end of a term has been approved by a special resolution of holders of Common Shares and the Manager is given 12 months written notice of termination or unless Freehold is given 12 months written notice of termination by the Manager prior to the end of a term. The current term of the Management Agreement will expire November 2013; however, as neither the Corporation nor the Manager provided a notice of termination prior to November 2012, the Management Agreement will be automatically renewed for another three year term. During 2012, the Board of Directors made the determination not to terminate the Management Agreement based on the recommendation of the Corporate Governance Committee that it was in the best interest of the Corporation that the Management Agreement be renewed.

The Management Agreement may be terminated by Freehold 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 written notice being given.

There may be circumstances in which the interests of the Manager will conflict with those of the Shareholders. The Manager provides similar management services to Canpar and Rife and may provide similar management services to others in the future. The Manager may acquire oil and gas properties on its own behalf or on behalf of persons other than Freehold. The Manager may manage and administer such additional properties, as well as enter into other types of energy-related management and advisory activities.

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 Manager will use all reasonable efforts to resolve such conflicts of interest in a manner which will treat Freehold and the other interested party fairly, taking into account all of the circumstances of Freehold and such interested party and will act honestly and in good faith in resolving such matters.

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, Freehold Resources and the Partnership.

Management Fee

The Manager receives a Management Fee, paid in Common Shares, based on the number of issued and outstanding Common Shares at the end of each quarter. Prior to completion of the Arrangement, the Management Fee was paid quarterly in Trust Units and upon formation of the Trust on November 25, 1996 was set at 20,000 Trust Units. The Management Fee was adjusted, based on the total issued and outstanding Trust Units, so that the quarterly Management Fee was in the same proportion as 20,000 was to the outstanding Trust Units on November 25, 1996, excluding Trust Units issued as payment of the Management Fee. Following completion of the Arrangement, the Management Fee continued to be paid and adjusted in the same manner except the Manager is entitled to receive Common Shares instead of Trust Units. As at December 31, 2012, the quarterly Management Fee was 47,873 Common Shares.

In conjunction with the implementation of the Arrangement, holders of Trust Units approved the reservation up to 1,000,000 Common Shares which may be issued as payment of the Management Fee under the Management Agreement. Presently under the Management Agreement, there are 636,067 Common Shares available for issuance as payment of the Management Fee.

General and Administrative Costs

The Manager is reimbursed for general and administrative costs incurred on behalf of the Corporation, Freehold Resources and the Partnership. General and administrative costs are generally charged to the Corporation, Freehold Resources and the Partnership by the Manager based on time spent and direct costs incurred in fulfilling the obligations of the Manager to the Corporation, Freehold Resources and the Partnership pursuant to the Management Agreement.

Share Based Compensation

The Corporation also accrues for its proportionate share 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.

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. The Deferred Share Unit Plan replaced the Deferred Trust Unit Plan of the Trust pursuant to the Arrangement. The obligations of the Trust under the Deferred Trust Unit Plan were assumed by Freehold under the Deferred Share Unit Plan pursuant to the Arrangement on the basis that the Trust Units which would be issued to a director holding Deferred Trust Units as if such director retired on the Effective Date were converted to notional Common Shares.

Retirement Benefit

The Corporation participates in its proportionate share of a retirement benefit for certain 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
William O. Ingram Alberta, Canada	President and Chief Executive Officer Director	President and Chief Executive Officer, Rife	October 1, 1996
Thomas J. Mullane Alberta, Canada	Executive Vice-President and Chief Operating Officer	Executive Vice-President and Chief Operating Officer, Rife	July 18, 2012
Darren G. Gunderson Alberta, Canada	Vice-President, Finance and Chief Financial Officer Director	Vice-President, Finance and Chief Financial Officer, Rife	July 2, 2007
Garry W. Bieber Alberta, Canada	Vice-President, Production	Vice-President, Production, Rife	August 13, 2008
J. Frank George Alberta, Canada	Vice-President, Exploration	Vice-President, Exploration, Rife	October 1, 1996
Michael J. Stone Alberta, Canada	Vice-President, Land	Vice-President, Land, Rife	March 1, 2010
Allan G. Glessing Alberta, Canada	Controller	Controller, Rife	September 18, 2008
Karen C. Taylor Alberta, Canada	Manager, Investor Relations and Corporate Secretary	Manager, Investor Relations and Corporate Secretary, Rife	February 1, 2008

As at March 7, 2013, the directors and senior officers of the Manager as a group beneficially owned, directly or indirectly, or exercised control or direction over 10,085 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 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 competition with the interests of the Shareholders.

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.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Other than as set out below, 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.

In the second quarter of 2009, a statement of claim was filed in the Alberta Court of Queen's Bench against the Trust for \$9 million. Freehold continued to be subject to this claim following completion of the Arrangement. The claim involves disputed land interests and royalty obligations. After receiving external legal advice, the Corporation has assessed the claim, believes it has no merit, and intends to defend itself aggressively in the claim. The claim's outcome is not determinable; therefore, no liability has been recorded in the Corporation's financial statements.

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 is a wholly-owned subsidiary of the CN Pension Trust Funds, which held 17,464,958 Common Shares as at March 7, 2013, representing approximately 26% of the outstanding Common Shares. The Manager receives certain compensation for providing management services to the Corporation, Freehold Resources and the Partnership as described under "*The Manager*". All transactions during 2012 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.

Pursuant to the Arrangement, to facilitate the continued relationship between the Manager and Freehold, the Management Agreement was amended and restated. The compensation arrangements with the Manager under the Management Agreement were not changed from the compensation arrangements with the Manager that existed prior to the Arrangement other than the Manager is now entitled to receive Common Shares instead of Trust Units in payment of the Management Fee. In connection with the Arrangement, holders of Trust Units approved the reservation of up to 1,000,000 Common Shares which may be issued as payment of the Management Fee under the Management Agreement.

In addition, pursuant to the Arrangement, the USA among the Manager, Freehold Resources and Computershare Trust Company of Canada, as trustee of the Trust, terminated and the Manager and Freehold entered into the Governance Agreement. The USA provided that the Unitholders were entitled to elect the majority of the members of the board of directors of Freehold Resources, and the Manager was entitled to elect the balance of the members of the board of directors of Freehold Resources. The Manager agreed to the reduction of its rights under the USA to the right to nominate, rather than appoint, directors of Freehold, to allow the Common Shares to be listed as “common shares” and not “restricted voting shares” on the TSX. 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.

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 after January 1, 2002, which are still in effect, are the following:

- (i) the Governance Agreement dated December 31, 2010, as described under the heading “*Governance – Governance Agreement*”;
- (ii) the Management Agreement dated January 1, 2011, as described under the heading “*The Manager – Management Agreement*”; and
- (iii) the credit facility between the Corporation (as successor to the Trust) and its lenders dated May 10, 2005, and amended on May 24, 2006, March 26, 2007, August 31, 2007, May 29, 2008, May 22, 2009, May 20, 2010, May 20, 2011, December 22, 2011, and May 11, 2012 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 evaluators.

Interest of Experts

KPMG LLP is the auditor of the Corporation and is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants, Alberta. As at the date hereof, the designated professionals (as defined in NI 51-102) of Trimble, as a group, beneficially owned, directly or indirectly, none of our outstanding securities nor any 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 Information Circular – Management Proxy Statement of the Corporation to be dated on or about April 3, 2013, which relates to the Annual Meeting of Shareholders to be held on May 15, 2013. Additional financial information is provided in Freehold’s consolidated financial statements for the year ended December 31, 2012 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 Information Circular – Proxy Statement 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
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, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012, 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.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10%, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2012, and identifies the respective portions thereof that we have evaluated and reported on to the Corporation’s management:

Independent Qualified Reserves Evaluator	Description and Preparation 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, 2012 Dated January 24, 2013	Canada	0	\$638,312	0	\$638,312

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. 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 7, 2013.

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**”) is 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, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012 estimated using forecast prices and costs.

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

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

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

(signed) “William O. Ingram”
William O. Ingram
President, Chief Executive Officer and Director

(signed) “Garry W. Bieber”
Garry W. Bieber
Vice-President, Production

(signed) “David J. Sandmeyer”
David J. Sandmeyer
Director and Chair, Reserves Committee

(signed) “Peter T. Harrison”
Peter T. Harrison
Director and Member, Reserves Committee

DATED as of this 7th day of March, 2013.

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 external auditors.
3. To enhance the external auditor’s independence.
4. To increase the transparency, credibility and objectivity of financial reporting.
5. To strengthen the role of the independent directors by facilitating in-depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) 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 (4) 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 auditor at least quarterly (in connection with the preparation of the annual and quarterly financial statements) and at such other times as the external auditor and the Committee consider appropriate.
6. The Committee will meet in-camera, without members of management or management directors, at the end of each meeting unless all the members have all indicated there is no need for an in-camera session. 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

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.
2. It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to Freehold’s internal control systems, which include:

- (a) identify, monitor and mitigate business risks; and
 - (b) ensure compliance with legal, ethical and regulatory requirements.
3. It is a primary responsibility of the Committee to 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) review of changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
 - (b) review of significant accruals, reserves or other estimates such as impairment testing;
 - (c) review of accounting treatment of unusual or non-recurring transactions;
 - (d) ascertain compliance with covenants under loan agreements;
 - (e) review adequacy of reclamation provisions;
 - (f) review disclosure requirements for commitments and contingencies;
 - (g) review adjustments raised by the external auditors, whether or not included in the financial statements;
 - (h) review unresolved differences between management and the external auditors; and
 - (i) obtain explanations of significant variances with comparative reporting periods.
4. The Committee is to review the financial statements, prospectuses, management's 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. With respect to the appointment of external auditors by the Board, the Committee will:
 - (a) annually review the performance of the external auditors
 - (b) recommend to the Board the appointment of external auditors;
 - (c) recommend to the Board the terms of engagement of the auditor, including the compensation of the auditors and confirmation 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. The Committee will 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. The Committee must 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. The Committee will review, on an annual basis, the risk management policies and procedures of Freehold, including hedging, litigation and insurance.
9. The Committee will review and approve management's hiring policies regarding current and former partners and employees of the present and former external auditor.
10. The Committee will establish a procedure 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. 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.
12. 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.