



## **2010 Annual Information Form**

**March 16, 2011**

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## ADVISORIES

### Forward-Looking Statements

Certain statements contained in this Annual Information Form (“AIF”) constitute forward-looking statements. These statements relate to future events or our future performance. 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 those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this AIF 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:

- the Manager’s anticipated acquisition strategy with respect to future acquisitions;
- the performance characteristics of our oil and natural gas properties;
- the estimated future value of the Corporation’s oil and gas reserves;
- 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;
- plans for development of undeveloped reserves;
- the funding and payment of future dividends;
- 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 gas properties in which the Corporation has an investment;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditures programs and the funding thereof.

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 or information are based on a number of factors and assumptions that have been used to develop such statements and information but which may prove to be incorrect. Although the Manager believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because the Manager can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions that may be identified in this document, 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 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 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;
- the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which the Corporation has an interest in oil and 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 and Other Oil and Gas Information – Significant Factors and Uncertainties*”.

Statements relating to “reserves” or “resources” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and 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.

### **Presentation of Oil and 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 of the Trust on December 31, 2010 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 Units**” means the deferred share units of the Corporation issued pursuant to the Deferred Share Unit Plan that are redeemable for Common Shares anytime after the retirement of a member of the Board of Directors.

“**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 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 Royalties 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 Fees**” means the fees payable to the Manager pursuant to the Management Agreement.

“**Manager**” means Rife Resources Management Ltd.

“**Net**” or “**net**” means:

- in relation to production and reserves, our working and non-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 “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 19, 2011 prepared by Trimble, evaluating the oil, natural gas, natural gas liquids and sulphur reserves attributable to the Corporation as at December 31, 2010.

“**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.

## Abbreviations

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

<b>To Convert From</b>	<b>To</b>	<b>Multiply By</b>
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 – 4<sup>th</sup> 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 – 4<sup>th</sup> 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 – 4<sup>th</sup> Avenue SW, Calgary, Alberta, T2P 3N4.

Pursuant to an agreement between Rife, a wholly-owned subsidiary of CN Pension Trust Funds, 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 27 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 of Freehold. Rife and the Manager also ensure that Freehold receives priority to consider acquisition opportunities. In addition, the Management Fee paid to the Manager are paid in Common Shares, which the Board of Directors of Freehold believes will align the interests of the Manager with the interests of the Shareholders. Based on these factors, the Board of Directors believes that maintaining Freehold’s relationship with the Manager is in the best interests of Freehold.

### 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. The head office of the Partnership is located at Suite 400, 144 – 4<sup>th</sup> Avenue SW, Calgary, Alberta, T2P 3N4.

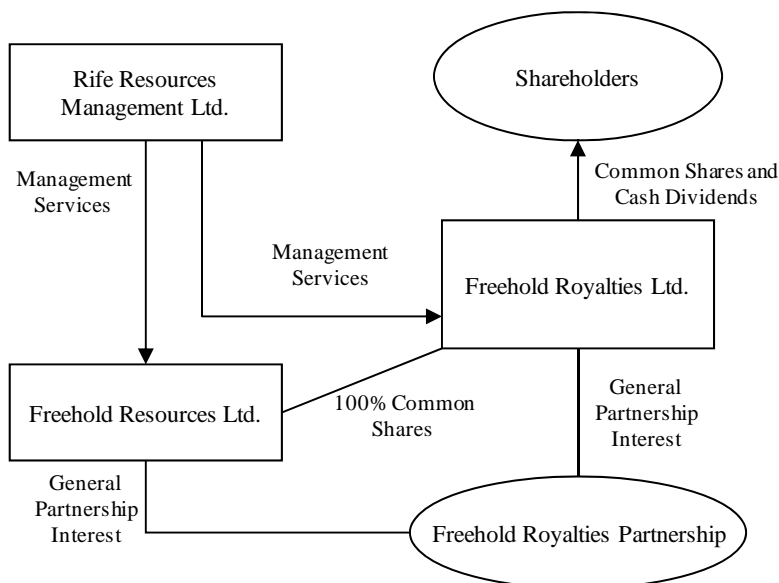
### Structure of the Corporation

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 and trusts, 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

Effective December 31, 2010, pursuant to the Arrangement under the ABCA 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 expects to continue to allocate cash flows as the Trust has historically done. Freehold expects to allocate cash flow primarily for capital expenditures, acquisitions, periodic debt repayments and dividends, which will be 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 three completed financial years.

### ***Year Ended December 31, 2008***

On July 7, 2008, we acquired certain royalty and minor working interests in Alberta for \$8.5 million. The acquisition included interests in units at Seven Persons, Bellshill Lake, Viking Kinsella, Beaverhill Lake, and Plain, and interests in oil and natural gas properties at Medicine Hat, Killam, Wainwright, Viking Kinsella, and Skara/Redwater.

### ***Year Ended December 31, 2009***

On December 10, 2009, we issued 7,618,750 Trust Units under a short-form prospectus offering at a price of \$15.15 per Trust Unit, which included 993,750 Trust Units issued pursuant to an over-allotment option provided to the underwriters. The net proceeds of the offering of approximately \$110.5 million were used, initially, to reduce bank indebtedness and, thereafter, for capital expenditures, acquisitions, and general corporate purposes.

On December 21, 2009, we acquired certain royalty interests for approximately \$10 million after closing adjustments, expanding our presence in the multi-zone prospective deep basin region of northwestern Alberta. The acquisition included royalty interests on 43,214 gross acres, of which 26,400 are located in the Bigstone area of Alberta and represented the creation of a 5% overriding royalty interest. The agreement provided for a drilling contribution by Freehold of up to \$1.9 million over five years following the acquisition to assist the vendor in the development of undeveloped lands in the Bigstone area. To December 31, 2010, Freehold has incurred \$0.5 million of this \$1.9 million commitment. Future opportunities on the Bigstone lands include natural gas and shallow Cardium oil. The remaining lands (16,814 gross acres) represented the assignment to Freehold of gross overriding royalties of varying percentages of production in 12 properties in Alberta and British Columbia.

### ***Year Ended December 31, 2010***

On February 12, 2010, we acquired 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.

## **Significant Acquisitions**

During the year ended December 31, 2010, 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 28,000 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.

Freehold does not expect to pay corporate income tax on income earned in 2011. Freehold's ability to generate additional tax pools, which can be used to shelter taxable income, depends on the level of future capital expenditures and acquisitions. Planned capital expenditures are not expected to generate significant new tax pools, and starting in 2012, it is expected that Freehold will be taxable at a rate of 15% to 20%.

## **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.

The Manager's acquisition strategy targets individual properties, or groups of properties, that generally comply with the following criteria and procedures:

- quality producing properties with an established production history and low reserve risk;
- on the basis of a technical and economic engineering evaluation;
- commodity price and exchange rate assumptions used in acquisition evaluations will be from an independent engineering firm acceptable to the Board of Directors as recommended by the Manager;
- each acquisition of a property, or group of properties, for a purchase price of \$5 million or more, will be based on a technical and economic valuation in a report prepared by an independent engineering firm, which, with the acceptance of the Board of Directors, may be modified to incorporate the technical views of the Manager;
- properties that have high netbacks;
- properties having strong third party operators or properties where the Manager or Freehold can assume operatorship;
- the expected economic life of a property, or group of properties, acquired in a single transaction will not be less than 10 years;
- no acquired property that is comprised of an interest in a single oil or natural gas pool shall represent more than 30% of the consolidated asset value of Freehold; and
- Freehold may acquire additional royalties from Canpar or others. The criteria for acquisition of such royalties may be varied from the criteria set out herein, with the approval of a majority of the independent members of the Board of Directors, in recognition of the unique economic characteristics of such royalties.

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 AND OTHER OIL AND GAS INFORMATION**

The statement of reserves data and other oil and gas information is set forth below (the "Statement"). The effective date of the Statement is December 31, 2010, and the preparation date of the Statement is January 19, 2011.

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, 2010 contained in the Trimble Report. The Reserves Data summarizes the oil, natural gas liquids, and natural gas 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 the standards contained in the Canadian Oil and Gas Evaluation (“COGE”) Handbook and the reserve definitions contained in NI 51-101. Information not required by NI 51-101 has been presented to provide continuity and additional information which 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 liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

## Forecast Prices and Costs

### SUMMARY OF OIL AND GAS RESERVES AS AT DECEMBER 31, 2010 FORECAST PRICES AND COSTS

Reserves Category	Reserves							
	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross <sup>(1)</sup> (Mbbls)	Net (Mbbls)	Gross <sup>(1)</sup> (Mbbls)	Net (Mbbls)	Gross <sup>(1)</sup> (MMcf)	Net (MMcf)	Gross <sup>(1)</sup> (Mbbls)	Net (Mbbls)
Proved								
Developed producing	1,597.2	3,330.2	854.5	4,562.6	4,763.3	35,379.4	190.0	846.8
Developed non-producing	71.3	62.5	-	-	58.2	51.3	7.0	4.5
Undeveloped	-	-	-	76.9	-	65.6	-	-
Total proved	1,668.5	3,392.7	854.5	4,639.5	4,821.5	35,496.3	197.0	851.3
Probable	973.3	1,835.1	689.1	3,240.1	2,963.0	19,859.5	117.6	444.7
Total proved plus probable	2,641.8	5,227.8	1,543.6	7,879.6	7,784.5	55,355.8	314.6	1,296.0

- 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.

NET PRESENT VALUES OF FUTURE NET REVENUE  
AS AT DECEMBER 31, 2010  
FORECAST PRICES AND COSTS

Reserves Category	Net Present Values of Future Net Revenue (\$000s) Before Income Taxes, Discounted at (% per year)				
	0%	5%	10%	15%	20%
Proved developed producing	851,792	604,051	475,253	396,874	344,009
Proved developed non-producing	923	387	140	16	(49)
Proved undeveloped	6,039	4,624	3,683	3,026	2,546
Total proved	858,754	609,062	479,076	399,916	346,506
Total probable	603,470	284,029	177,156	128,172	100,570
Total proved plus probable	1,462,224	893,091	656,232	528,088	447,076

Reserves Category	Net Present Values of Future Net Revenue (\$000s) After Income Taxes, Discounted at (% per year)				
	0%	5%	10%	15%	20%
Proved developed producing	693,101	497,114	395,077	332,893	290,894
Proved developed non-producing	705	285	89	(12)	(65)
Proved undeveloped	4,517	3,512	2,836	2,358	2,006
Total proved	698,323	500,911	398,002	335,239	292,835
Total probable	449,564	214,552	135,504	99,165	78,636
Total proved plus probable	1,147,887	715,463	533,506	434,404	371,471

TOTAL FUTURE NET REVENUE  
(UNDISCOUNTED)  
AS AT DECEMBER 31, 2010  
FORECAST PRICES AND COSTS

(\$000s)	Reserves Category	
	Proved	Proved Plus Probable
Royalty Income	734,806	1,248,260
Revenue from working interest properties	291,505	504,881
Royalty expense on working interest properties	(42,210)	(77,332)
Operating costs	(117,476)	(199,793)
Development costs	(819)	(5,685)
Well abandonment and reclamation costs	(7,053)	(8,107)
Future net revenue before income taxes	858,754	1,462,224
Future income taxes	(160,431)	(314,336)
Future net revenue after income taxes	698,323	1,147,887

FUTURE NET REVENUE  
BY PRODUCTION GROUP  
AS AT DECEMBER 31, 2010  
FORECAST PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes	
		Discounted at 10% per year (\$000s)	Unit Value <sup>(1)</sup>
Proved	Light and Medium Oil (including solution gas and other by-products)	151,975	\$45.42/bbl
	Heavy Oil (including solution gas and other by-products)	205,750	\$44.34/bbl
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	121,350	\$4.00/Mcf
Proved plus probable	Light and Medium Oil (including solution gas and other by-products)	201,608	\$39.09/bbl
	Heavy Oil (including solution gas and other by-products)	287,099	\$36.43/bbl
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	167,524	\$3.52/Mcf

- The Unit Value is calculated by dividing the discounted Future Net Revenue by the net reserves of the principal product type.

## Definitions and Other Notes

- Columns may not add due to rounding.
- The oil, natural gas liquids and natural gas 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.

- Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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:

- 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.
  - Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
  - Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (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, 2010 utilized in the Trimble Report were as follows:

#### FORECAST PRICES USED IN ESTIMATES AS AT DECEMBER 31, 2010

Year	Oil			Natural Gas			Natural Gas Liquids			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 \$Cdn/MMBtu	Propane \$Cdn/bbl	Butane \$Cdn/bbl	Pentane \$Cdn/bbl	%/Year	\$US/\$Cdn
2011	88.40	93.08	74.46	81.91	80.04	4.04	55.20	62.44	95.32	1.50	0.93
2012	89.14	93.85	75.08	82.59	80.71	4.66	55.66	62.95	96.11	1.50	0.93
2013	88.77	93.43	72.87	81.28	78.48	4.99	55.41	62.67	95.68	1.50	0.93
2014	88.88	93.54	71.09	80.44	76.70	6.58	55.47	62.75	95.79	1.50	0.93
2015	90.22	94.95	72.16	81.66	77.86	6.69	56.31	63.69	97.24	1.50	0.93
2016	91.57	96.38	73.25	82.89	79.03	6.80	57.16	64.65	98.71	1.50	0.93
2017	92.94	97.84	74.36	84.14	80.23	6.91	58.02	65.63	100.20	1.50	0.93
2018	94.34	99.32	75.48	85.41	81.44	7.02	58.90	66.62	101.71	1.50	0.93
2019	95.75	100.81	76.62	86.70	82.67	7.14	59.79	67.63	103.25	1.50	0.93
2020	97.19	102.34	77.78	88.01	83.92	7.26	60.69	68.65	104.81	1.50	0.93
Thereafter, per year:	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	+1.5%	1.50	0.93

FREEHOLD WEIGHTED AVERAGE PRICES  
YEAR ENDED DECEMBER 31, 2010

	Light and Medium Oil (\$/bbl)	Heavy Oil (\$/bbl)	Natural Gas (\$/Mcf)	Natural Gas Liquids (\$/bbl)
Freehold weighted average price	73.28	60.41	3.64	51.33

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:
  - (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, natural gas lines and power lines, to the extent necessary in developing the reserves;
  - (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
  - (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
  - (d) provide improved recovery systems.
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)
2011	70	71
2012	71	2,478
2013	527	2,868
2014	29	29
2015	30	30
Remainder	92	209
<b>Total</b>	<b>819</b>	<b>5,685</b>

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.

8. The forecast price and cost assumptions assume the continuance of current laws and regulations.
9. The extent and character of all factual data supplied to Trimble were accepted by Trimble as represented. No field inspection was conducted.

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 GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS

	Light and Medium Oil (Mbbbls)	Heavy Oil (Mbbbls)	Associated and Non- Associated Gas (MMcf)	Natural Gas Liquids (Mbbbls)	Oil Equivalent (Mboe)
<b>Gross Proved Reserves</b>					
December 31, 2009	1,761	1,042	4,796	179	3,780
Extensions	193	45	311	14	304
Improved recovery	-	-	-	-	-
Technical revisions	33	54	892	37	273
Discoveries	-	-	-	-	-
Acquisitions	-	-	-	-	-
Dispositions	(8)	-	-	-	(8)
Economic factors	(3)	-	(12)	(1)	(6)
Production	(308)	(286)	(1,165)	(32)	(820)
<b>December 31, 2010<sup>(1)</sup></b>	<b>1,669</b>	<b>855</b>	<b>4,822</b>	<b>197</b>	<b>3,524</b>
<b>Gross Probable Reserves</b>					
December 31, 2009	1,000	717	2,889	89	2,287
Extensions	181	57	553	27	358
Improved recovery	-	-	-	-	-
Technical revisions	(195)	(85)	(477)	1	(358)
Discoveries	-	-	-	-	-
Acquisitions	-	-	-	-	-
Dispositions	(11)	-	-	-	(11)
Economic factors	(2)	-	(2)	-	(2)
Production	-	-	-	-	-
<b>December 31, 2010<sup>(1)</sup></b>	<b>973</b>	<b>689</b>	<b>2,963</b>	<b>118</b>	<b>2,274</b>
<b>Gross Proved Plus Probable Reserves</b>					
December 31, 2009	2,761	1,759	7,685	268	6,068
Extensions	375	102	864	41	661
Improved recovery	-	-	-	-	-
Technical revisions	(162)	(31)	415	39	(86)
Discoveries	-	-	-	-	-
Acquisitions	-	-	-	-	-
Dispositions	(19)	-	-	-	(19)
Economic factors	(5)	-	(14)	(1)	(8)
Production	(308)	(286)	(1,165)	(32)	(820)
<b>December 31, 2010<sup>(1)</sup></b>	<b>2,642</b>	<b>1,544</b>	<b>7,785</b>	<b>315</b>	<b>5,797</b>

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 NET RESERVES  
BY PRINCIPAL PRODUCT TYPE  
FORECAST PRICES AND COSTS**

	Light and Medium Oil (Mbbbls)	Heavy Oil (Mbbbls)	Associated and Non- Associated Gas (MMcf)	Natural Gas Liquids (Mbbbls)	Oil Equivalent (Mboe)
<b>Net Proved Reserves</b>					
December 31, 2009	3,596	4,889	35,555	824	15,236
Extensions	188	141	682	23	465
Improved recovery	-	-	-	-	-
Technical revisions	89	372	2,497	110	986
Discoveries	-	-	-	-	-
Acquisitions	85	181	3,223	54	857
Dispositions	(8)	-	-	-	(8)
Economic factors	10	3	24	-	17
Production	(568)	(946)	(6,483)	(159)	(2,753)
<b>December 31, 2010<sup>(1)</sup></b>	<b>3,393</b>	<b>4,640</b>	<b>35,496</b>	<b>851</b>	<b>14,800</b>
<b>Net Probable Reserves</b>					
December 31, 2009	1,974	3,270	19,060	398	8,818
Extensions	178	114	919	40	485
Improved recovery	-	-	-	-	-
Technical revisions	(350)	(247)	(2,029)	(30)	(965)
Discoveries	-	-	-	-	-
Acquisitions	43	99	1,896	37	495
Dispositions	(11)	-	-	-	(11)
Economic factors	1	4	15	-	7
Production	-	-	-	-	-
<b>December 31, 2010<sup>(1)</sup></b>	<b>1,835</b>	<b>3,240</b>	<b>19,860</b>	<b>445</b>	<b>8,830</b>
<b>Net Proved Plus Probable Reserves</b>					
December 31, 2009	5,571	8,159	54,615	1,222	24,054
Extensions	366	255	1,600	63	950
Improved recovery	-	-	-	-	-
Technical revisions	(261)	125	468	80	22
Discoveries	-	-	-	-	-
Acquisitions	128	280	5,118	91	1,352
Dispositions	(19)	-	(1)	-	(19)
Economic factors	11	7	38	-	24
Production	(568)	(946)	(6,483)	(159)	(2,753)
<b>December 31, 2010<sup>(1)</sup></b>	<b>5,228</b>	<b>7,880</b>	<b>55,356</b>	<b>1,296</b>	<b>23,629</b>

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.

In each of the last three years, proved undeveloped reserves have been less than 1% of total proved plus probable reserves assigned to the Corporation. At December 31, 2010, the proved undeveloped reserves assigned in the Trimble Report were only 0.6% of the total proved reserves.

For the years 2008 to 2010, probable undeveloped reserves have been less than 1.2% of total proved plus probable reserves assigned in the Trimble report. At December 31, 2010, probable undeveloped reserves were only 0.9% of the total proved plus probable reserves assigned in the Trimble Report.

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

Year	Light and Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Associated and Non- Associated Gas (MMcf)	Natural Gas Liquids (Mbbls)
Prior	76.9	-	65.6	-
2008	-	-	-	-
2009	-	-	-	-
2010	-	-	-	-
<b>Total Booked for Current Year</b>	<b>76.9</b>	<b>-</b>	<b>65.6</b>	<b>-</b>

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

Year	Light and Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Associated and Non- Associated Gas (MMcf)	Natural Gas Liquids (Mbbls)
Prior	81.0	12.2	777.6	-
2008	-	-	-	-
2009	-	-	-	-
2010	-	-	-	-
<b>Total Booked for Current Year</b>	<b>81.0</b>	<b>12.2</b>	<b>777.6</b>	<b>-</b>

### 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**

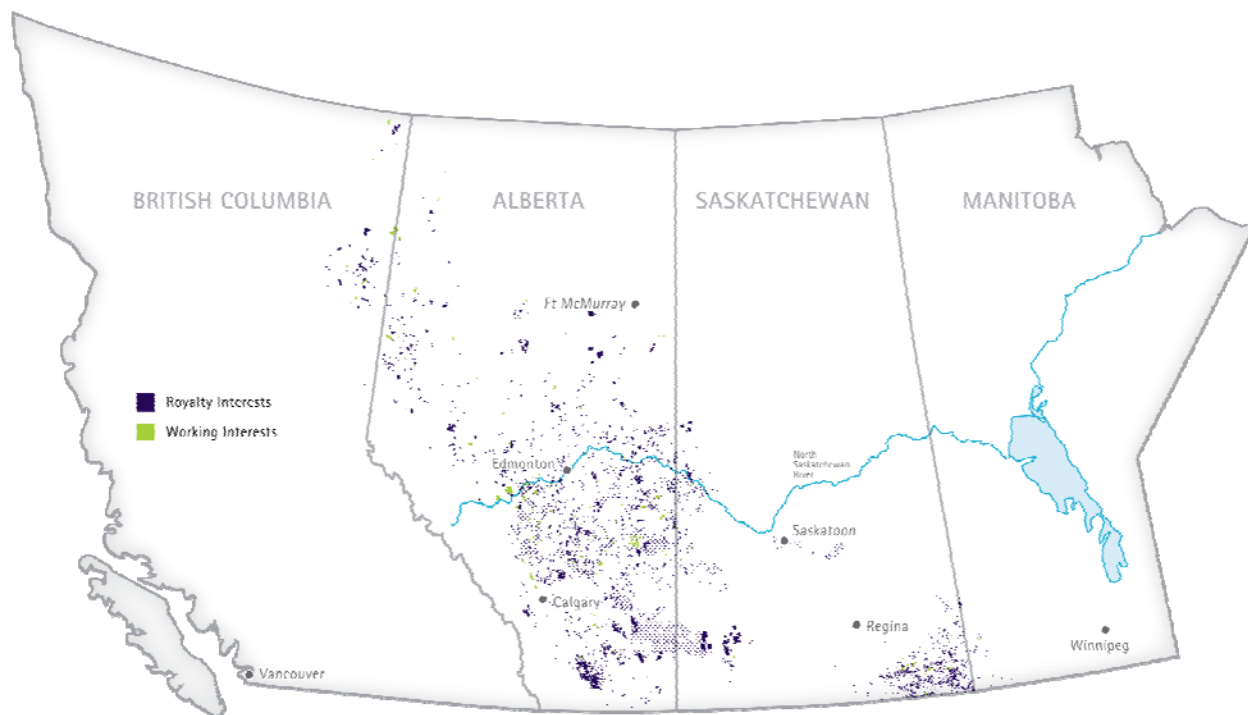
Freehold has oil and natural gas interests in producing and non-producing lands located in British Columbia, Alberta, Saskatchewan, Manitoba, and Ontario, encompassing approximately 2.8 million gross acres at December 31, 2010. The majority of our land, 67% is in Alberta, with 18% in Saskatchewan, 10% in Ontario, 4% 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 production. The properties are operated by experienced operators, including, among others, Apache Canada Ltd., ARC Resources Ltd., Canadian Natural Resources Limited, Cenovus Energy Inc., City of Medicine Hat, ConocoPhillips Canada, Crescent Point Energy Corp., Delphi Energy Corp., Devon Canada, Enerplus Resources Corp., Harvest Operations Corp., Husky Oil Operations Limited, NAL Resources Ltd., Pengrowth Corporation, Penn West Petroleum Ltd., PetroBakken Energy Ltd., Rife Resources Ltd., Suncor Energy Inc., and Taqa North 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.

## LAND HOLDINGS



### 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) gross overriding royalty lands owned by third parties upon which such third parties pay royalties or net profits interests to the Corporation, which may or may not be interests in land; and (iii) royalty assumption land 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. Mineral title and royalty assumptions lands do not expire, while gross overriding royalties may expire at the end of the lease's productive life.

### Mineral Title Lands

Mineral title lands are the most valuable category of Royalty Lands, because the mineral rights are held in perpetuity. Royalty revenue is derived from the royalties payable to the Corporation (lessor royalties) through the lease documents issued to the companies (lessees) that have producing wells located thereon. In 2010, this category of land accounted for 21% of our total royalty acreage and provided approximately 48% 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 545,100 acres, of which 82% are leased and 18% are unleased. Certain of the leased mineral title lands have, over time, been included within 194 oil and natural gas production units, which ensure royalty payments to the Corporation over the entire producing life of the unit. The mineral title lands also include approximately 163,100 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's Bay. The majority of Freehold's unleased mineral title lands are in Southeast Saskatchewan.

### Gross Overriding Royalty Lands

The Corporation holds gross overriding royalties in approximately 1,930,100 acres, of which approximately 567,800 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 owned by a number of third party oil and gas companies in respect of which varying royalties or net profits interests have been reserved to the Corporation. In 2010, this category of land accounted for 75% of our total royalty acreage and provided approximately 48% 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.

Certain of the gross overriding royalties have been included within 121 oil and natural gas production units.

### Royalty Assumption Lands

The Corporation holds royalty interests in approximately 95,100 acres, of which approximately 20,000 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. Certain of the royalty interests associated with the royalty assumption lands have been included in 28 oil and natural gas production units. In 2010, this category of land accounted for 4% of our total royalty acreage and provided approximately 4% of our royalty revenue.

### Description of Royalty Lands

The Corporation's royalty interests represent a geologically and geographically diverse portfolio of properties extending from northeast British Columbia to Ontario (not shown on the map), with 65% of the gross royalty acreage in Alberta.

The Manager oversees Freehold's royalty interests through three multi-disciplined technical teams, each assigned to manage a geographic region: Alberta West, Lloydminster, and Saskatchewan East.

The following table summarizes by area the Corporation's average royalty interest, net reserves, and reserves value as at December 31, 2010, and wells drilled, oil and natural gas production, and royalty revenue for 2010 for the Corporation's Royalty Lands:

Royalty Lands	Average Royalty Interest <sup>(1)</sup> (%)	2010 Wells Drilled (gross)	2010 Production (boe/d)	Net Proved Plus Probable Reserves <sup>(1)</sup> (Mboe)	2010 Royalty Income <sup>(2)</sup> (\$000s)	2010 Future Net Revenue Discounted at 10%/year <sup>(1)(2)</sup> (\$000s)	(%)
Alberta West	1.0	565	2,681	8,977.0	34,581	227,207	41.5
Lloydminster	4.7	63	2,013	6,457.0	39,359	220,607	40.3
Saskatchewan East	0.8	151	879	3,154.0	19,216	99,415	18.2
Total	1.4	779	5,573	18,587.0	93,156	547,229	100.0

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, gross wells and production unit interests owned by Freehold:

Area	Total Acres	Undeveloped Acres <sup>(1)</sup>	Non-Unitized		Unitized		
			Natural Gas Wells	Oil Wells	Production Units	Natural Gas Wells	Oil Wells
Alberta West	1,467,781	309,472	4,058	1,178	208	6,280	3,627
Lloydminster	403,500	78,357	638	2,113	46	927	1,774
Saskatchewan East	676,201	355,748	1,275	1,314	89	7	3,560
Potash	22,865	7,351	-	-	-	-	-
Total	2,570,347	750,928	5,971	4,605	343	7,214	8,961

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 57% of Freehold's total royalty acreage, with interests in 1,467,781 gross acres, of which 309,472 acres are undeveloped. The region has 4,058 non-unitized natural gas wells, 1,178 non-unitized oil wells, and 208 production units currently containing 6,280 natural gas wells and 3,627 oil wells. In 2010, industry operators drilled 565 gross wells in the region.

The Trimble Report assigned total proved reserves of 2,033 MMbbls of oil and NGL and 22,919 MMcf of natural gas and proved plus probable reserves of 3,124 MMbbls of oil and NGL and 35,114 MMcf of natural gas. On a boe basis, production increased 16% in 2010 and the region accounted for 48% of total royalty production. Oil and NGL production averaged 868 bbls/d and natural gas production averaged 10,881 Mcf/d.

In recent years, several operators have begun to target known, regionally extensive but technically challenging oil and natural gas deposits. Increasingly, they are drilling horizontal wells, which is highly effective at providing maximum exposure to tight reservoirs, and employing multi-stage fracture technology to stimulate the resource and increase recovery rates. The most significant of these resource plays is the Cardium trend, which extends across 42 oil fields in west central Alberta and represents about 20% of the estimated remaining reserves in the entire Western Canada Sedimentary Basin.

The largest field by far is Pembina, discovered in 1953. Two approaches are being used to unlock the potential of the Cardium. Some operators are using multi-fracture horizontal wells on the edges of the field where the reservoir is too thin or too tight to produce from vertical wells. Others are drilling in the main part of the field, targeting larger oil pockets. While there is considerable potential given the overall size of the resource, each pool will require a different approach and it may take many years to perfect the appropriate techniques. On Royalty Lands situated on the Cardium oil trend, Freehold has title interests ranging from 27% to 100%.

### ***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, with interests in 403,500 gross acres, of which 78,357 acres are undeveloped. The region has 638 non-unitized natural gas wells, 2,113 non-unitized oil wells, and 46 production units currently containing 927 natural gas wells and 1,774 oil wells. In 2010, industry operators drilled 63 gross wells in the region.

The Trimble Report assigned total proved reserves of 3,206 MMbbls of oil and NGL and 3,663 MMcf of natural gas and proved plus probable reserves of 5,478 MMbbls of oil and NGL and 5,870 MMcf of natural gas. On a boe basis, production increased 1% in 2010 and the region accounted for 36% of total royalty production. Oil and NGL production averaged 1,681 bbls/d and natural gas production averaged 2,000 Mcf/d.

The northern part of the region is characterized by the production of heavier oil and/or natural gas from shallow Mannville sands. In the southern part of the area, production is predominately light gravity oil and natural gas from the Viking formation and low to medium gravity oil from the Mannville. This region contains the majority of Freehold's heavy oil production.

### ***Saskatchewan East***

The Saskatchewan East region includes all of Freehold's royalty interests in Saskatchewan and Manitoba, and minor royalty interests in Ontario, except for lands in the Lloydminster region.

This region contains 27% of Freehold's total royalty acreage, with interests in 676,201 gross acres, of which 355,748 acres are undeveloped. The region has 1,275 non-unitized natural gas wells, 1,314 non-unitized oil wells, and 89 production units currently containing 7 natural gas wells and 3,560 oil wells. In 2010, industry operators drilled 151 gross wells in the region.

The Trimble Report assigned total proved reserves of 1,290 MMbbls of oil and NGL and 4,498 MMcf of natural gas and proved plus probable reserves of 1,954 MMbbls of oil and NGL and 7,201 MMcf of natural gas. On a boe basis, production increased 6% in 2010 and the region accounted for 16% of total royalty production. Oil and NGL production averaged 646 bbls/d and natural gas production averaged 1,395 Mcf/d.

In Saskatchewan and Manitoba, production is largely light to medium oil production from the Paleozoic aged reservoirs of the Williston Basin. The industry has been developing the deeper Bakken resource play in Southeast Saskatchewan, where Freehold has both leased and unleased mineral title acreage.

### ***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 royalties derived from the potash leases are calculated in the same manner as royalties payable to the Province of Saskatchewan from provincially owned potash rights.

The potash mines from which the Corporation receives royalties are operated by Potash Corporation of Saskatchewan and The Mosaic Company. In 2010, the Corporation received revenue of approximately \$1.7 million from the production of 11.5 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 750,928 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, 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 1,257 unitized and non-unitized development wells were drilled. 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.

Years Ended December 31 <sup>(1)</sup> (gross wells)	2010		2009	
	Unitized	Non-Unitized	Unitized	Non-Unitized
Oil wells	77	103	77	43
Natural gas wells	403	109	235	63
Service/other wells	25	58	4	54
Dry and abandoned wells	-	4	-	2
<b>Total</b>	<b>505</b>	<b>274</b>	<b>316</b>	<b>162</b>
<b>Success rate</b>	<b>100%</b>	<b>99%</b>	<b>100%</b>	<b>98%</b>

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 2010, based on forecast prices and costs:

	Light and Medium Oil (Mbbbls)	Heavy Oil (Mbbbls)	Associated and Non- Associated Gas (MMcf)	Natural Gas Liquids (Mbbbls)	Oil Equivalent (Mboe)
<b>Net Proved Reserves <sup>(1)</sup></b>					
December 31, 2009	1,998	3,894	31,176	693	11,781
Extensions	29	107	403	11	214
Improved recovery	-	-	-	-	-
Technical revisions	70	486	1,767	82	932
Discoveries	-	-	-	-	-
Acquisitions	85	181	3,223	54	857
Dispositions	-	-	(1)	-	-
Economic factors	-	-	-	-	-
Production	(309)	(718)	(5,488)	(134)	(2,076)
<b>December 31, 2010 <sup>(2)</sup></b>	<b>1,872</b>	<b>3,950</b>	<b>31,080</b>	<b>706</b>	<b>11,708</b>
<b>Net Probable Reserves <sup>(1)</sup></b>					
December 31, 2009	1,087	2,605	16,521	331	6,776
Extensions	26	71	419	20	187
Improved recovery	-	-	-	-	-
Technical revisions	(173)	(87)	(1,730)	(31)	(579)
Discoveries	-	-	-	-	-
Acquisitions	43	99	1,896	37	495
Dispositions	-	-	-	-	-
Economic factors	-	-	-	-	-
Production	-	-	-	-	-
<b>December 31, 2010 <sup>(2)</sup></b>	<b>984</b>	<b>2,687</b>	<b>17,105</b>	<b>357</b>	<b>6,879</b>
<b>Net Proved Plus Probable Reserves <sup>(1)</sup></b>					
December 31, 2009	3,084	6,499	47,697	1,024	18,557
Extensions	55	178	823	32	401
Improved recovery	-	-	-	-	-
Technical revisions	(102)	399	37	51	354
Discoveries	-	-	-	-	-
Acquisitions	128	280	5,118	91	1,352
Dispositions	-	-	(1)	-	-
Economic factors	-	-	-	-	-
Production	(309)	(718)	(5,488)	(134)	(2,076)
<b>December 31, 2010 <sup>(2)</sup></b>	<b>2,856</b>	<b>6,638</b>	<b>48,185</b>	<b>1,063</b>	<b>18,587</b>

1. Excludes minor royalty interests attributable to certain working interest properties.
2. Columns may not add due to rounding.

### Working Interest Properties

We own working interests in 99 oil and gas properties. Production from these properties is comprised of approximately 74% oil and NGL and 26% natural gas. Working interest production accounted for 2,042 boe/d in 2010, down from 2,155 boe/d in 2009. In 2010, 32 (9.3 net) wells were drilled, compared with 28 (8.2 net) wells during 2009. In 2011, we expect to spend approximately \$20 million on development activities on various properties.

Effective January 1, 2010, we adjusted our method of allocating royalty interest and working interest production on properties where we have both a royalty interest and a working interest, (Hayter and Southeast Saskatchewan). The adjustment effectively increased royalty production by approximately 190 boe/d for 2010, reducing working interest volumes by the same amount. The prior period results were not restated. As a result, our 2010 Southeast Saskatchewan and Hayter working interest production results were lower than they would have been using the previous method.

Over half of our working interest production comes from three properties as shown in the following table.

Property	Working Interest <sup>(1)</sup> (%)	2010 Wells Drilled Gross (net)	2010 Production (boe/d)	Net Proved Plus Probable Reserves (Mboe)	2010 Net Pre-Tax Operating Income <sup>(4)</sup> (\$000s)	Future Net Revenue Discounted at 10%/year	
						(\$000s)	(%)
Southeast Saskatchewan <sup>(2)(5)</sup>	10.65	12 (5.9)	560	487.3	11,292	26,445	24.3
Hayter (Alberta) <sup>(2)</sup>	23.52	9 (1.6)	350	701.6	4,700	18,406	16.9
Pembina Cardium Unit No. 9 (Alberta) <sup>(3)</sup>	9.97	6 (0.6)	153	1,753.4	2,105	23,649	21.7
Other (96 properties)	3.93	5 (1.2)	979	2,099.8	8,833	40,502	37.2
<b>Total</b>	<b>6.45</b>	<b>32 (9.3)</b>	<b>2,042</b>	<b>5,042.1</b>	<b>26,930</b>	<b>109,002</b>	<b>100</b>

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. Reserves include a 0.6% royalty interest.
4. Excludes income from interest and other.
5. Includes non-unit and unit interests.

### ***Southeast Saskatchewan***

In the Southeast Saskatchewan area, we own an average non-unit working interest of 35.9%, which includes interests in 85 wells. The Trimble Report has assigned to our unit and non-unit holdings in this area total proved reserves of 181 Mbbls of oil and NGL and 31 MMcf of natural gas and proved plus probable reserves of 475 Mbbls of oil and NGL and 74 MMcf of natural gas.

We have title interests ranging from 10% to 100%, and working interests ranging from 2.5% to 100%. From 2005 to 2009, we participated in 57 (16.5 net) wells. Of these, 28 (7.7 net) were Bakken wells (Freehold operates two 100% wells) and the balance were various Mississippian zones. This participation is the result of the particularly favorable, oil based economics of these opportunities. Approximately 30,000 gross acres of the Bakken mineral title lands are unleased.

In 2010, we participated in 12 (5.5 net) wells, primarily on company owned mineral title lands. Of these, 6 (3.6 net) were Bakken wells, all of which Freehold operated. Capital expenditures totaled \$12.1 million in 2010, and in 2011 we have allocated two-thirds of our capital budget to this area.

Production in Southeast Saskatchewan remained relatively unchanged in 2010. Oil and NGL production was 535 bbls/d and natural gas production was 147 Mcf/d.

### ***Hayter, Alberta***

In the Hayter area, we own an average working interest of 23.52%, which includes interests in 137 wells. The Trimble Report has assigned total proved reserves of 404 Mbbls of oil and NGL and 16 MMcf of natural gas and proved plus probable reserves of 696 Mbbls of oil and NGL and 28 MMcf of natural gas to this property. The Hayter Dina B pool is situated in the northeast portion of Township 40 Range 1 W4M covering portions of six sections. The pool produces 15° API oil from an average net pay interval of approximately 50 feet. The pool was discovered and delineated with vertical wells but due to the presence of an active bottom water drive has been more effectively developed with horizontal drilling. Production decreased 33% in 2010. Oil and NGL production was 348 bbls/d and natural gas production was 13 Mcf/d. In 2010, 9 (1.6 net) wells were drilled and capital expenditures totaled \$1.9 million. In 2011, the operator (Rife Resources Ltd.) plans to optimize the water handling facilities and drill additional infill wells.

### ***Pembina Cardium Unit No. 9, Alberta***

In the Pembina Cardium Unit No. 9, we own a unit working interest of 9.97% and a 0.6% royalty interest, which includes interests in 169 wells. The Trimble Report has assigned total proved reserves of 952 Mbbls of oil and NGL and 1,557 MMcf of natural gas and proved plus probable reserves of 1,375 Mbbls of oil and NGL and 2,273 MMcf of natural gas to this property. This unit has an extremely long reserve life and has been under waterflood for more than 45 years. In 2010, capital expenditures were \$2.3 million, and included the drilling of six (0.6 net) wells. Production increased 6% in 2010. Oil and NGL production was 119 bbls/d and natural gas production was 206 Mcf/d.

### ***Other Working Interest Properties***

We own various working interests in 96 other properties, which accounted for 48% of the working interest production volumes during 2010 but which individually contributed less than 100 boe/d to production. Development activities in 2010 included the drilling of 5 (1.2 net) wells.

### ***Working Interest Wells***

The following table sets forth the number and status of wells as at December 31, 2010 in which we have a working interest that are producing or considered capable of production:

Property	Producing <sup>(1)</sup>				Non-Producing <sup>(1)(2)(3)</sup>			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Southeast Saskatchewan	146	20.2	-	-	31	5.2	-	-
Hayter (Alberta)	125	29.5	-	-	12	2.8	-	-
Pembina Cardium Unit No. 9 (Alberta)	150	14.9	-	-	19	1.9	-	-
Other (96 properties)	435	28.7	556	19.2	105	12.8	104	5.2
Total <sup>(4)</sup>	856	93.4	556	19.2	167	22.7	104	5.2

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, 2010 and December 31, 2009. No exploratory wells were drilled during this period.

Years Ended December 31 (gross wells)	2010		2009	
	Gross	Net	Gross	Net
Oil wells	30	9.1	25	7.6
Natural gas wells	2	0.2	1	-
Service/other wells	-	-	1	0.1
Dry and abandoned wells	-	-	1	0.5
Total	32	9.3	28	8.2
Success rate	100%		96%	

**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 2010, based on forecast prices and costs:

	Light and Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Associated and Non- Associated Gas (MMcf)	Natural Gas Liquids (Mbbls)	Oil Equivalent (Mboe)
<b>Gross Proved Reserves<sup>(1)</sup></b>					
December 31, 2009	1,761	1,042	4,796	179	3,780
Extensions	193	45	311	14	304
Improved recovery	-	-	-	-	-
Technical revisions	33	54	892	37	273
Discoveries	-	-	-	-	-
Acquisitions	-	-	-	-	-
Dispositions	(8)	-	-	-	(8)
Economic factors	(3)	-	(12)	(1)	(6)
Production	(308)	(286)	(1,165)	(32)	(820)
<b>December 31, 2010<sup>(2)</sup></b>	<b>1,669</b>	<b>855</b>	<b>4,822</b>	<b>197</b>	<b>3,524</b>
<b>Gross Probable Reserves<sup>(1)</sup></b>					
December 31, 2009	1,000	717	2,889	89	2,287
Extensions	181	57	553	27	358
Improved recovery	-	-	-	-	-
Technical revisions	(195)	(85)	(477)	1	(358)
Discoveries	-	-	-	-	-
Acquisitions	-	-	-	-	-
Dispositions	(11)	-	-	-	(11)
Economic factors	(2)	-	(2)	-	(2)
Production	-	-	-	-	-
<b>December 31, 2010<sup>(2)</sup></b>	<b>973</b>	<b>689</b>	<b>2,963</b>	<b>118</b>	<b>2,274</b>
<b>Gross Proved Plus Probable Reserves<sup>(1)</sup></b>					
December 31, 2009	2,761	1,759	7,685	268	6,068
Extensions	375	102	864	41	661
Improved recovery	-	-	-	-	-
Technical revisions	(162)	(31)	415	39	(86)
Discoveries	-	-	-	-	-
Acquisitions	-	-	-	-	-
Dispositions	(19)	-	-	-	(19)
Economic factors	(5)	-	(14)	(1)	(8)
Production	(308)	(286)	(1,165)	(32)	(820)
<b>December 31, 2010<sup>(2)</sup></b>	<b>2,642</b>	<b>1,544</b>	<b>7,785</b>	<b>315</b>	<b>5,797</b>

1. The working interest properties include certain minor royalty interests; however the above table does not reflect such royalty interests because the reconciliation is presented on a gross basis.
2. Columns may not add due to rounding.

## 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, 2010.

Working Interest Properties	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	671	66.4	115	13.2	338	15.3	89	4.4
Saskatchewan	162	25.7	47	9.3	1	-	2	0.7
British Columbia	11	0.4	5	0.2	217	3.9	13	0.1
Manitoba	12	0.9	-	-	-	-	-	-
Total <sup>(1)</sup>	856	93.4	167	22.7	556	19.2	104	5.2

1. Columns may not add due to rounding.

Royalty Lands <sup>(1)</sup>	Non-Unitized		Unitized	
	Natural Gas		Natural Gas	
	Wells	Oil Wells	Wells	Oil Wells
Alberta	4,459	2,477	7,171	4,930
Saskatchewan	1,207	2,076	38	3,960
British Columbia	126	32	5	39
Manitoba	-	20	-	32
Ontario	179	-	-	-
Total <sup>(1)</sup>	5,971	4,605	7,214	8,961

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, 2010.

	Undeveloped Acres			
	Royalty Lands		Working Interest Lands	
	Gross	Net	Gross	Net
Alberta	336,068		36,804	5,348
Saskatchewan	192,599		2,262	848
British Columbia	26,559		4,080	51
Manitoba	1,884		40	-
Ontario	193,818		-	-
Total	750,928		43,186	6,247

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 17,547 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.

## Tax Horizon

Freehold does not expect to pay corporate income tax on income earned in 2011. Freehold's ability to generate additional tax pools, which can be used to shelter taxable income, depends on the level of future capital expenditures and acquisitions. Planned capital expenditures are not expected to generate significant new tax pools, and starting in 2012, it is expected that Freehold will be taxable at a rate of 15% to 20%.

## Capital Expenditures

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

The following table summarizes capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to the Corporation's activities for the year ended December 31, 2010. The acquisition costs were for royalty interest properties and the development costs were on our working interest or unleased mineral title lands.

	(\$000s)
Property acquisition costs	
Proved properties	38,600
Undeveloped/unproved properties	-
Development costs	18,054
<b>Total</b>	<b>56,654</b>

## Production Estimates

The following table sets out the volume of gross and net production estimated for the year ended December 31, 2010 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".

Reserves Category	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Oil Equivalent	
	Gross <sup>(1)</sup>	Net	Gross <sup>(1)</sup>	Net	Gross <sup>(1)</sup>	Net	Gross <sup>(1)</sup>	Net	Gross <sup>(1)</sup>	Net
	(bbls/d)	(bbls/d)	(bbls/d)	(bbls/d)	(Mcf/d)	(Mcf/d)	(bbls/d)	(bbls/d)	(boe/d)	(boe/d)
Proved										
Developed producing	608.2	1,220.5	598.6	2,126.3	2,284.9	14,509.3	63.9	349.6	1,651.6	6,114.7
Developed non-producing	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	-	6.3	-	5.2	-	-	-	7.2
<b>Total proved</b>	<b>608.2</b>	<b>1,220.5</b>	<b>598.6</b>	<b>2,132.6</b>	<b>2,284.9</b>	<b>14,514.5</b>	<b>63.9</b>	<b>349.6</b>	<b>1,651.6</b>	<b>6,121.8</b>
Probable	197.0	223.6	100.8	227.7	297.0	1,358.6	9.4	40.4	356.7	718.0
<b>Total proved plus probable<sup>(2)</sup></b>	<b>805.2</b>	<b>1,444.1</b>	<b>699.5</b>	<b>2,360.3</b>	<b>2,581.9</b>	<b>15,873.2</b>	<b>73.3</b>	<b>389.9</b>	<b>2,008.3</b>	<b>6,839.8</b>

- 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.
- 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:

	Quarter Ended 2010				Quarter Ended 2009			
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Average daily production <sup>(1)</sup>								
Light and Medium Oil (bbls/d)	2,220	2,111	1,950	2,006	2,114	1,863	1,945	2,067
Heavy Oil (bbls/d)	2,257	2,216	2,289	2,353	2,537	2,242	2,325	2,412
Natural Gas (Mcf/d)	18,972	16,913	18,028	15,919	14,827	15,315	16,136	16,202
NGL (bbls/d)	333	349	411	319	280	336	335	343
Combined (boe/d)	7,972	7,495	7,655	7,331	7,402	6,994	7,295	7,522
Average price realized								
Light and Medium Oil (\$/bbl)	75.90	70.78	70.02	76.21	72.00	65.71	61.47	45.94
Heavy Oil (\$/bbl)	61.52	57.77	56.91	65.31	62.73	57.59	57.07	37.52
Natural Gas (\$/Mcf)	3.29	3.20	3.44	4.76	3.56	2.78	3.02	5.26
NGL (\$/bbl)	57.57	47.32	48.50	52.85	50.39	40.50	37.41	40.75
Combined (\$/boe)	48.80	46.44	45.56	54.45	51.09	44.01	42.99	37.85
Royalty expense and mineral tax <sup>(2)</sup>								
Light and Medium Oil (\$/bbl)	2.90	3.14	2.38	3.72	3.37	2.41	1.41	1.18
Heavy Oil (\$/bbl)	1.42	1.63	1.26	1.76	1.42	(4.78)	1.13	2.82
Natural Gas (\$/Mcf)	-	(0.08)	0.05	0.10	0.08	0.06	0.07	0.28
NGL (\$/bbl)	3.64	2.83	3.70	3.51	4.08	2.37	2.16	2.18
Combined (\$/boe)	1.36	1.31	1.29	1.95	1.76	(0.65)	0.98	1.92
Operating expenses (\$/boe) <sup>(3)</sup>								
Light and Medium Oil (\$/bbl)	5.22	7.51	7.60	6.98	7.72	7.43	6.40	6.00
Heavy Oil (\$/bbl)	6.36	5.82	5.05	4.42	4.19	3.59	5.52	7.21
Natural Gas (\$/Mcf)	0.22	0.24	0.31	0.29	0.25	0.18	0.77	0.13
NGL (\$/bbl)	2.25	2.00	2.07	1.85	2.00	1.26	4.53	0.75
Combined (\$/boe)	3.87	4.46	4.29	4.03	4.22	3.59	5.39	4.27
Netback received <sup>(4)</sup>								
Light and Medium Oil (\$/bbl)	67.78	60.13	60.04	65.51	60.91	55.87	53.66	38.76
Heavy Oil (\$/bbl)	53.74	50.32	50.60	59.13	57.12	58.78	50.42	27.49
Natural Gas (\$/Mcf)	3.07	3.04	3.08	4.37	3.23	2.54	2.18	4.85
NGL (\$/bbl)	51.68	42.49	42.73	47.49	44.31	36.87	30.72	37.82
Combined (\$/boe)	43.57	40.67	39.98	48.47	45.11	41.07	36.62	31.66

1. Before deduction of royalty expenses.
2. Royalty expense and mineral tax 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.

The following table summarizes our average daily production from important regions or fields for the year ended December 31, 2010:

	Light and Medium Oil (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (bbls/d)	Oil Equivalent (boe/d)
<b>Royalty Lands</b>					
Alberta West	561	52	10,881	254	2,681
Lloydminster	66	1,609	2,000	6	2,013
Saskatchewan East	633	5	1,395	8	879
<b>Working Interest Properties</b>					
Hayter (Alberta)	-	348	13	-	350
Southeast Saskatchewan	523	-	147	12	560
Pembina Cardium Unit No. 9 (Alberta)	107	-	206	12	153
Other (96 properties)	183	265	2,823	60	979
<b>Total</b>	<b>2,073</b>	<b>2,279</b>	<b>17,465</b>	<b>352</b>	<b>7,615</b>

## Environmental Obligations

Freehold does not operate any of its oil and gas assets, nor does the Corporation have any employees. Freehold is a member of the Canadian Association of Petroleum Producers (CAPP). We encourage our operators to participate and excel in the CAPP Stewardship Program, by aligning their operations with industry best practices and communicating clearly that meeting or exceeding regulatory requirements is expected. The Manager has a comprehensive environment, health and safety program to protect the health and safety of its employees, contractors, and the public.

### *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 generated from operations. At December 31, 2010, our estimated undiscounted share of future environmental and reclamation obligations for the working interest properties was approximately \$22.6 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 180 net wells at the estimated costs identified in the following table:

As at December 31, 2010	Abandonment and Reclamation Costs (Net of Salvage Value) (\$000s)	
	Undiscounted	Discounted at 10%
Total costs as at December 31, 2010	22,560	3,262
Total costs not deducted from future net revenue	14,452	1,229
Expected to be paid in 2011	-	-
Expected to be paid in 2012	277	237
Expected to be paid in 2013	386	297

## 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, 2010, we had \$145 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 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, 2010, 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, 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 and Saskatchewan, 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.

### 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. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, transportation capacity, 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 and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

#### *Natural Gas*

The price of the vast majority of natural gas produced in western Canada is now determined through the liquid market established at the Alberta "NIT" hub rather than through direct negotiation between buyers and sellers. 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 m<sup>3</sup>/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 and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

### Pipeline Capacity

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production levels of oil and natural gas in western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

### 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. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. 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 prohibits discriminatory border restrictions and export taxes. NAFTA also 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.

## 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 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, from time to time, carved out of the working interest owner's interest 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.

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("NRF") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, 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. Royalty rates for conventional oil under the NRF ranged from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps were set at \$120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 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/m<sup>3</sup> compared to the previous royalty curve.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF ranged from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps were set at \$16.59/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 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 NRF. Prior to payout, 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: 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. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold mineral 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.

In April 2005, the Government of Alberta implemented the Innovative Energy Technologies Program (the "IETP"), which 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 is backed by a \$200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty

adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended 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 spud subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 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 5-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 new program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers were only able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that had already elected to adopt such rates as of that date were permitted to switch to Alberta's conventional royalty structure up until February 15, 2011. On January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a \$200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new 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;
- 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, 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.

In addition to the foregoing, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

### **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 (“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 as an incentive for the production and marketing of natural gas which might otherwise have been flared.

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. For natural gas, the freehold production tax 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.

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

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to \$100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;
- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of 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 spud between December 1, 2003 and September 1, 2009;
- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;
- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m<sup>3</sup> of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;
- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m<sup>3</sup> 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 royalty breaks for low productivity natural gas wells with average monthly production under 25,000 m<sup>3</sup> during the first 12 production months and average daily production less than 23 m<sup>3</sup> for every metre of marginal well depth;
- *Ultra-Marginal Royalty Reduction Program* providing additional royalty breaks for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m<sup>3</sup> during the first 12 production months and average daily production less than 11.5 m<sup>3</sup> (development wells) or 17 m<sup>3</sup> (exploratory wildcat wells) for every 100 metres of marginal well depth;
- *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 event on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m<sup>3</sup> 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 improve, or make possible, the access to new and underdeveloped oil and gas areas. In both 2009 and 2010, the Government of British Columbia allocated \$120 million in royalty credits for oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the “**Royalty Relief Program**”). British Columbia’s existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. Wells spud between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An additional \$50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

### **Saskatchewan**

In Saskatchewan, the amount payable as a royalty 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 classified as “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 new oil (not classified as either third tier oil or fourth tier oil). 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.

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

The amount payable as a royalty 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 vintage of the natural gas. Like conventional oil, natural gas may be classified as “non-associated gas” or “associated gas” and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m<sup>3</sup> of gas for every m<sup>3</sup> of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* which replaces the existing *Freehold Oil and Gas Production Tax Act* and is intended to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new Act.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of \$50 per thousand m<sup>3</sup> for third and fourth tier gas and \$35 per thousand m<sup>3</sup> 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 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 and freehold tax rates on incentive volumes of 8,000 m<sup>3</sup> for deep development vertical oil wells, 4,000 m<sup>3</sup> for non-deep exploratory vertical oil wells and 16,000 m<sup>3</sup> for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);
- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m<sup>3</sup> for qualifying exploratory gas wells;
- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m<sup>3</sup> for non-deep horizontal oil wells and 16,000 m<sup>3</sup> for deep horizontal oil wells (more than 1,700 metres or within certain formations);
- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout; and
- *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% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout.

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 will be limited in its carry forward to seven years since the Government of Canada’s initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan’s RTR will be wound down as a result of the Government of Canada’s plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

## Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. 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. Oil and natural gas located in such provinces can also be privately owned 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 and Saskatchewan 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’s policy of deep rights reversion was expanded 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.

In Alberta, the NRF includes 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. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, 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.

## 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 requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. 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.

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, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are 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, 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. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

## Climate Change Regulation

### *Federal*

In December 2002, the Government of Canada ratified the Kyoto Protocol (“**Kyoto Protocol**”), which requires a reduction in greenhouse gas (“**GHG**”) emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its greenhouse gas emissions levels to 6% below 1990 “business-as-usual” levels by 2012.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to “ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change.” It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

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 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 either a facility-specific, sector-wide or 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.

The Updated Action Plan makes a distinction between “Existing Facilities” and “New Facilities”. For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. “New Facilities” are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility’s physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method

of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage (“CCS”) technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO<sub>2</sub> equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO<sub>2</sub> equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at \$15 per tonne of CO<sub>2</sub> equivalent for the 2010 to 2012 period, rising to \$20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm’s regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 7 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark (the “**Copenhagen Conference**”) resulted in the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. From November 29 to December 10, 2010, a meeting between representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

In response to the Copenhagen Accord, the Government of Canada indicated on January 29, 2010 that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which were discussed above.

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. 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 greenhouse gas emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

On December 23, 2010, the United States Environmental Protection Agency indicated its intention to impose greenhouse gas emissions standards for fossil fuel-fired power plants by July, 2011 and for refineries by December, 2011.

## **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 greenhouse gases a year are subject to comply 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 similar compliance mechanisms as the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the “**Fund**”) at a rate of \$15 per tonne of CO<sub>2</sub> 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. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol’s Clean Development Mechanism.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which 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 initial level of the tax was set at \$10 per tonne of CO<sub>2</sub> equivalent and rose to \$15 per tonne of CO<sub>2</sub> equivalent on July 1, 2009 and \$20 per tonne of CO<sub>2</sub> equivalent on July 1, 2010. It is scheduled to further increase at a rate of \$5 per tonne of CO<sub>2</sub> equivalent on July 1 of every year until it reaches \$30 per tonne of CO<sub>2</sub> equivalent on July 31, 2012. 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.

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 will come into force by regulation of the Lieutenant Governor in Council. 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 greenhouse gas emissions. It is expected that greenhouse gas emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO<sub>2</sub> equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in greenhouse gas emissions. Although more specific details of British Columbia’s cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO<sub>2</sub> equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO<sub>2</sub> equivalents per year are required to have their emissions reports verified by a third party.

### **Saskatchewan**

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the “**MRGGA**”) to regulate greenhouse gas 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 greenhouse gas emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

## **RISK FACTORS**

The following is a summary of certain risk factors relating to the business of the Corporation. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this document. Shareholders and potential Shareholders should consider carefully the information contained herein and, in particular, the following risk factors.

## Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, 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 gas, royalty rates, 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 and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates 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 and such variations could be material.

In accordance with applicable securities laws, Trimble 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 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 third party oil and natural gas companies are expected to undertake in future years. The reserves and estimated cash flows to be derived therefrom 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 has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

## Volatility of Oil and Natural Gas Prices

The Corporation's operational results and financial condition, and therefore the revenue from the Corporation's royalty interest and working interest properties will be dependent on the prices received for oil and natural gas production. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and 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, dividends to Shareholders, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and 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. The Corporation may manage the risk associated with changes in commodity prices by entering into oil or natural gas price hedges, but has not done so to date. If the Corporation hedges its commodity price exposure, the Corporation will forego the benefits it would otherwise experience if commodity prices were to increase. In addition, commodity hedging activities could expose the Corporation to losses. To the extent that the Corporation engages in risk management activities related to commodity prices, it will be subject to credit risks associated with counterparties with which it contracts.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation, which could require that a portion, or all, of the Corporation's bank debt be repaid.

## Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating 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. Although economic conditions improved towards the latter portion of 2009 and in 2010, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and to result in high volatility in the stock market.

## Variations in Interest Rates and Foreign Exchange Rates

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a decrease in dividends to Shareholders, as well as impact the market price of the Common Shares on the TSX.

Our operating costs are generally paid in Canadian dollars. World oil prices are quoted in U.S. dollars. The price that Canadian producers receive is therefore affected by the Canadian/U.S. dollar exchange rate. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues.

The Corporation may initiate certain hedges to attempt to mitigate these variations in rates, but has not done so to date. To the extent that the Corporation engages in risk management activities related to foreign exchange rates, it will be subject to credit risk associated with counterparties with which it contracts. Increases in the Canadian/U.S. dollar exchange rate and future Canadian/U.S. dollar exchange rates will impact future dividends and the future value of the Corporation's reserves as determined by independent evaluators.

## Depletion of Reserves

The Corporation has certain unique attributes that differentiate it from other oil and gas industry participants. Without commodity price increases or cost effective acquisition and development activities, dividends to Shareholders will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. The Corporation will not be reinvesting cash flow in the same manner as other industry participants. As a result, the Corporation may have difficulty maintaining current production levels and reserves. The Corporation's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on activities of the working interest owners of the Royalty Lands and Freehold's success in exploiting its reserve base and acquiring additional reserves on its working interest properties. Without reserve additions through acquisition or development activities, the Corporation's reserves and production will decline. There can be no assurance that the Manager, on behalf of Freehold, will be successful in developing or acquiring additional reserves on terms that meet the Corporation's investment objectives.

## Changes in Legislation

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "*Industry Conditions*". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Income tax laws, or other laws or government incentive programs relating to the oil and gas industry, such as resource taxation, royalty rates, or environmental regulations may in the future be changed or interpreted in a manner that adversely affects the Corporation and its Shareholders. Tax authorities having jurisdiction over the Corporation or the Shareholders may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the detriment of the Corporation or the detriment of its Shareholders.

## Operational Matters

The operation of oil and natural gas wells involves a number of operating and natural hazards, which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to Freehold and possible liability to third parties. Freehold will maintain liability insurance, where available, in amounts consistent with industry standards. Business

interruption insurance may also be purchased for selected facilities, to the extent that such insurance is available. Freehold may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities may reduce Freehold's cash flow available for dividends.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat Freehold's claim to certain royalty or working interest properties. A reduction of the Corporation's cash flow available for dividends could result in such circumstances.

## Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government that may be amended from time to time. Freehold's operations may require licences from various governmental authorities. There can be no assurance that Freehold will be able to obtain all necessary licences and permits that may be required to carry out exploration and development at its projects.

## Environmental Concerns

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 and abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such 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. There can be no assurance that the Corporation will be able to satisfy actual future environmental and reclamation obligations.

## Climate Change and Greenhouse Gases

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". There has been much public debate with respect to Canada's ability to meet these targets and the federal government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with greenhouse gas emissions legislation in the jurisdiction in which the Corporation operates. The Corporation will also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which are now expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. 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. See "*Industry Conditions – Climate Change Regulation*".

## Debt Service

Amounts paid in respect of interest and principal on debt incurred by the Corporation will reduce the Corporation's cash flow. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of dividends to Shareholders. Certain covenants of the agreements with the lender may also limit dividends paid by the Corporation. Although the Manager and Freehold believe the credit facility is sufficient for the Corporation's immediate requirements, there can be no assurance that the amount will be adequate for the future financial obligations of the Corporation or that additional funds will be able to be obtained.

The lenders have been provided with security over substantially all of the assets of the Corporation. If the Corporation becomes unable to pay its debt service charges or otherwise commits an event of default such as bankruptcy, the lender may foreclose on or sell all or some of Freehold's assets.

## **Delay in Payment**

In addition to the usual delays in payment by purchasers of oil and natural gas to the payors of the Corporation's royalties and/or operators of the properties, and by those payors and operators to the Manager or Freehold, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operators of expenses incurred in the operation of the Corporation's working interests or the establishment by the operators of reserves for such expenses.

## **Reliance on the Manager**

Shareholders are dependent on the management of the Manager in respect of the administration and management of all matters relating to the Corporation's royalties and working interest properties, the Corporation and Common Shares. Investors who are not willing to rely on the management of the Manager should not invest in the Common Shares. The Corporation's success depends in large measure on certain key personnel of the Manager. 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 contributions of the existing management team of the Manager 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 Manager will be able to continue to attract and retain all personnel necessary for the development and operation of the Corporation's business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Manager.

## **Additional Financing**

In the normal course of making capital investments to maintain and expand the oil and natural gas reserves of the Corporation additional Common Shares may be issued from treasury, which may result in a decline in production per Common Share and reserves per Common Share. Additionally, from time to time the Corporation may issue Common Shares from treasury in order to reduce debt and maintain a more optimal capital structure. To the extent that external sources of capital, including the issuance of additional Common Shares become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy, its dividends and on its business, financial condition, results of operations and prospects. To the extent that the Corporation is required to use funds generated from operations to finance capital expenditures or property acquisitions, the level of dividends to Shareholders will be reduced.

## **Geo-Political Risks**

The marketability and price of oil and natural gas is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue. In addition, the oil and natural gas properties, wells and facilities in which the Corporation has an interest could be subject to a terrorist attack. If any of such 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 will not have insurance to protect against the risk from terrorism.

## **Competition**

There is strong competition relating to all aspects of the oil and gas industry. There are numerous companies in the oil and gas industry, which are competing for the acquisitions of properties with longer life reserves and properties with exploitation and development opportunities. As a result of such increasing competition, it will be more difficult to acquire reserves on beneficial terms. The Corporation will actively compete for reserve acquisitions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial and other resources than the Corporation.

## **Potential Conflicts of Interest**

There may be circumstances in which the interests of the Manager will conflict with those of Shareholders. The Manager may acquire oil and natural gas properties on its own behalf or on behalf of persons other than the Shareholders. The Manager may

manage and administer the royalty interest and working interest properties of the Corporation, as well as enter into other types of energy-related management, advisory and investment activities. Neither the Manager, nor its management, will carry on their full-time activity on behalf of Shareholders and, when acting on their own behalf or on behalf of others, may at times act in competition with the interests of Shareholders. Circumstances may arise where members of the board of directors of Freehold are directors or officers of corporations that are in competition to the interests of the Corporation. No assurances can be given that opportunities identified by such board members will be provided to the Corporation. See "*Conflicts of Interest*".

## **Title**

Although satisfactory title reviews of the properties are conducted in accordance with industry standards, those title reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Corporation to a property. A reduction of Royalty Income or in the revenue earned from working interest properties could result in those circumstances.

## **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 59,493,292 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 and commenced trading under the symbol "FRU" following the completion of the Arrangement on January 7, 2011. Prior to completion of the Arrangement, the outstanding Trust Units were listed for trading on the TSX under the symbol "FRU.UN". As a result of the completion of the Arrangement, the Trust Units were delisted from the TSX after the close of markets on January 6, 2011. The following table sets forth the high and low trading prices and the aggregate trading volume of the Trust Units as reported by the TSX for the periods indicated, and the trading history of the Common Shares since January 7, 2011.

TORONTO STOCK EXCHANGE  
TRUST UNIT/Common SHARES TRADING RANGE

	(Cdn\$ per Trust Unit/Common Share)			Volume Traded
	High	Low	Close	
<b>2010</b>				
January	16.14	15.08	15.27	3,778,395
February	16.41	15.11	16.35	1,760,069
March	17.59	16.25	16.94	2,404,621
April	18.05	16.69	17.90	1,766,887
May	17.90	15.31	16.23	2,635,356
June	17.22	15.80	15.84	1,626,585
July	17.14	15.73	16.72	1,134,020
August	16.95	15.95	16.65	1,664,223
September	17.90	16.20	17.89	1,716,486
October	19.86	17.75	19.00	2,465,608
November	20.00	18.75	20.00	2,597,132
December	21.14	19.12	20.49	2,216,685
<b>2011</b>				
January	20.70	20.08	20.51	322,102
February	22.54	20.60	21.81	2,127,008
March 1 to 15	22.93	21.30	22.00	1,110,157

### 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, 2010, our legal stated capital was approximately \$250 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 15<sup>th</sup> day of the following month. It is expected that the dividends will be “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. Although it is expected that dividends of Freehold will qualify as “eligible dividends” for the purposes of the Tax Act, no assurances can be given that all dividends will be designated as “eligible dividends” or qualify as “eligible dividends”. Notwithstanding the foregoing, 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 completion of the Arrangement, Freehold has declared cash dividends of \$0.14 per Common Share for Shareholders of record on January 31, 2011, February 28, 2011, and March 31, 2011, payable on February 15, 2011, March 15, 2011, and April 15, 2011 respectively.

The table below sets forth the amount of cash distributions the Trust paid on the Trust Units during the three most recently completed financial years prior to completion of the Arrangement:

Record Date	Payment Date	Cdn\$ per Trust Unit
<b>2008</b>		
January 31, 2008	February 15, 2008	0.15
February 28, 2008	March 15, 2008	0.15
March 31, 2008	April 15, 2008	0.15
April 30, 2008	May 15, 2008	0.18
May 31, 2008	June 15, 2008	0.18
June 30, 2008	July 15, 2008	0.25
July 31, 2008	August 15, 2008	0.25
August 31, 2008	September 15, 2008	0.25
September 30, 2008	October 15, 2008	0.25
October 31, 2008	November 15, 2008	0.25
November 30, 2008	December 15, 2008	0.25
December 31, 2008	January 15, 2009	0.60 <sup>(1)</sup>
		2.91

Record Date	Payment Date	Cdn\$ per Trust Unit
<b>2009</b>		
January 31, 2009	February 15, 2009	0.10
February 28, 2009	March 15, 2009	0.10
March 31, 2009	April 15, 2009	0.10
April 30, 2009	May 15, 2009	0.10
May 31, 2009	June 15, 2009	0.10
June 30, 2009	July 15, 2009	0.10
July 31, 2009	August 15, 2009	0.10
August 31, 2009	September 15, 2009	0.12
September 30, 2009	October 15, 2009	0.12
October 31, 2009	November 15, 2009	0.12
November 30, 2009	December 15, 2009	0.20 <sup>(2)</sup>
December 31, 2009	January 15, 2010	0.14
		1.40

Record Date	Payment Date	Cdn\$ per Trust Unit
<b>2010</b>		
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 15, 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 15, 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

1. Includes additional \$0.35 distribution in respect of 2008 income.
2. Includes additional \$0.06 distribution in respect of 2009 income.

## 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. CN Pension Trust Funds, which currently owns approximately 26% of Freehold’s Common Shares, are currently participating in the DRIP.

## 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.

# 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 \$5.0 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, all of which were members of the Board of Directors of Freehold Resources immediately prior to the Arrangement. The name, province of residence, position held and principal occupation of each director of Freehold are set out below:

<b>Name and Province of Residence</b>	<b>Position with Freehold Resources</b>	<b>Principal Occupation</b>	<b>Director/Officer Since</b>
D. Nolan Blades <sup>1,2,5</sup> Alberta, Canada	Chair of the Board and Director	President, Sunny Gables Holdings Ltd. (private holding company)	July 29, 1996
Harry S. Campbell, Q.C. <sup>3,4,5</sup> Alberta, Canada	Director	Vice-Chair, Burnet, Duckworth & Palmer LLP (barristers and solicitors)	July 29, 1996
Tullio Cedraschi <sup>3,5</sup> Quebec, Canada	Director	Corporate Director	January 21, 1998
Peter T. Harrison <sup>4,6</sup> Quebec, Canada	Director	Manager, Canadian Equities and Oil & Gas Investments CN Investment Division	July 29, 1996
William O. Ingram <sup>6</sup> Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer, Rife Resources Ltd. (private oil and gas exploration and production company)	May 13, 2009
P. Michael Maher <sup>1,2,3,5</sup> Alberta, Canada	Director	Professor, Haskayne School of Business University of Calgary	July 29, 1996
David J. Sandmeyer <sup>4,5</sup> Alberta, Canada	Director	Corporate Director	July 29, 1996
Rodger A. Tourigny <sup>1,2,5</sup> Alberta, Canada	Director	President, Tourigny Management Ltd.	November 10, 2009

1. Member of Audit Committee.
2. Member of Compensation Committee.
3. Member of Governance and Nominating Committee.
4. Member of Reserves Committee.
5. Independent directors of Freehold Resources who were elected by the Shareholders at the last annual meeting of the Trust on May 12, 2010.
6. Directors appointed by the Manager pursuant to the USA prior to its termination in accordance with the terms of the Arrangement.

## Officers of Freehold

The senior management of Freehold is the same as the senior management of Freehold Resources immediately prior to completion of the Arrangement. The following table sets forth the name, province of residence, position held and principal occupation of each of the officers of Freehold:

<b>Name and Province of Residence</b>	<b>Position with Freehold</b>	<b>Principal Occupation</b>	<b>Director/Officer Since</b>
William O. Ingram Alberta, Canada	President and Chief Executive Officer	President and Chief Executive Officer, Rife Resources Ltd.	July 29, 1996
Darren G. Gunderson Alberta, Canada	Vice-President, Finance and Chief Financial Officer	Vice-President, Finance and Chief Financial Officer, Rife Resources Ltd.	November 13, 2003
Garry W. Bieber Alberta, Canada	Vice-President, Production	Vice-President, Production, Rife Resources Ltd.	August 13, 2008
J. Frank George Alberta, Canada	Vice-President, Exploration	Vice-President, Exploration, Rife Resources Ltd.	July 29, 1996
Michael J. Stone Alberta, Canada	Vice-President, Land	Vice-President, Land, Rife Resources Ltd.	March 1, 2010
Michael J. Mogan Alberta, Canada	Controller	Controller, Freehold Resources Ltd.	August 13, 2008
Karen C. Taylor Alberta, Canada	Manager, Investor Relations and Corporate Secretary	Manager, Investor Relations and Corporate Secretary, Rife Resources Ltd.	February 27, 2008

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. Harrison who was appointed Manager, Canadian Equities and Oil & Gas Investments, of the CN Investment Division on August 24, 2009, Mr. Sandmeyer, who retired as President and Chief Executive Officer of Freehold Resources, Rife and Canpar on May 13, 2009, Mr. Cedraschi who retired as President and Chief Executive Officer of CN Investment Division on January 31, 2008 and Mr. Stone, who prior to joining Rife in 2008 was Vice-President, Land with Real Resources Ltd.

As at March 16, 2011, the directors and senior officers of Freehold, as a group, beneficially owned or controlled, directly or indirectly, 85,225 Common Shares or less than 1% of the issued and outstanding Common Shares. CN Pension Trust Funds, owned, directly or indirectly, 15,234,470 Common Shares (25.61%) of the Corporation as at March 16, 2011. The Manager has received 1,553,917 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 16, 2011.

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

### *D. Nolan Blades*

Nolan Blades is President of Sunny Gables Holdings Ltd. (Calgary) and a Professional Engineer with extensive experience in the oil and gas industry. Mr. Blades has obtained significant financial experience and exposure to accounting and financial issues as President and Chief Executive Officer of Pursuit Resources Corp. (1993 – 2000), and as a director of a number of companies. He is currently a director of Gemini Corporation.

### *William O. Ingram*

Bill Ingram joined Rife (Calgary) in 1984 and was appointed President and Chief Executive Officer 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 is a Professional Engineer and holds a Bachelor of Science degree in Chemical Engineering from the University of Alberta. He is a member of The Association of Professional Engineers, Geologists and Geophysicists of Alberta (APPEGA).

### *Harry S. Campbell, Q.C.*

Harry Campbell is Vice-Chair 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 currently a Director of Delphi Energy Corp., EmberClear Corp. and The Cathay Investment Fund Limited.

***Tullio Cedraschi***

Tullio Cedraschi is a Corporate Director and the former President and Chief Executive Officer of the CN Investment Division (Montreal), which manages one of the largest corporate pension funds in Canada. He is currently a Director of the Toronto Stock Exchange. He is Governor Emeritus of McGill University, and Governor of the National Theatre School of Canada. He holds an MBA from McGill University.

***Peter T. Harrison***

Peter Harrison is Manager, Canadian Equities and Oil & 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 holds 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 currently a director of Pace Oil & Gas Ltd.

***P. Michael Maher***

Michael 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***

David 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. He is currently a Director of Anderson Energy Ltd. and Delphi Energy Corp. A graduate of the University of Saskatchewan, he holds a Bachelor of Science degree in Mechanical Engineering and is a Professional Engineer.

***Rodger A. Tourigny***

Rodger Tourigny is President of Tourigny Management Ltd., 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. Mr. Tourigny holds a Bachelor of Commerce degree from the University of Saskatchewan and is a Chartered Accountant.

***Darren G. Gunderson***

Darren Gunderson is currently the Vice-President, Finance and Chief Financial Officer of the Corporation and he 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 holds a Bachelor of Commerce degree from the University of Saskatchewan and is a Certified General Accountant.

***Garry W. Bieber***

Garry Bieber is currently the Vice-President, Production of Freehold and he 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 & Safety, production and drilling operations, and economic evaluations. Mr. Bieber holds a Bachelor of Science degree in Geological Engineering from the University of Saskatchewan and is a Professional Engineer.

***J. Frank George***

Frank George, Vice-President, Exploration of Freehold, joined Rife in 1983 as Chief Geologist and became Vice-President, Exploration in 1994. He is responsible for the management and coordination of all exploration and geological evaluation activities of Rife. In 1996, he was appointed Vice-President, Exploitation of Freehold Resources and 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***

Michael Stone, Vice-President, Land of Freehold, 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 holds a Bachelor of Commerce degree from the University of Calgary and is a member of the Canadian Association of Petroleum Landmen.

***Michael J. Mogan***

Michael Mogan, Controller of Freehold, 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***

Karen Taylor, Manager, Investor Relations and Corporate Secretary, 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**

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

Mr. Tourigny was a director of Shenandoah Resources Ltd. ("Shenandoah") and resigned on September 17, 2002. Shenandoah was placed into receivership on September 17, 2002. On November 8, 2002 and October 23, 2002, the Alberta Securities Commission and British Columbia Securities Commission issued cease trade orders because Shenandoah had failed to file certain required financial statements. The cease trade orders remain outstanding. The common shares of Shenandoah were suspended from trading on the TSX Venture Exchange on April 24, 2002.

**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. D. Nolan Blades and Mr. 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	
	2010	2009
Audit fees <sup>(1)</sup>	142,000	174,000
Audit-related fees <sup>(2)</sup>	70,000	80,000
Tax fees <sup>(3)</sup>	22,900	10,348
<b>Total</b>	<b>234,900</b>	<b>264,348</b>

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. During 2010, the services provided in this category include corporate conversion review work and advisory services relating to International Financial Reporting Standards (IFRS). During 2009, the services provided in this category include French translation related to Freehold's equity offering in December of that year and advisory services relating to IFRS.
3. Tax fees consist of fees for tax compliance and advisory services. During 2010 and 2009, the services provided in this category included assistance and advice in relation to Shareholder taxation issues and the review of corporate income tax returns. In addition, during 2010, additional tax services provided include 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 which are 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, 2010, the Manager had 110 full and part-time employees. 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, farmin and farmout 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.

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 and Freehold Resources 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 Fees***

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. At the time of completion of the Arrangement, the quarterly Management Fee was 42,778 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 1,000,000 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 "Manager's LTIP"). 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 and reaching the age of 65. 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:

<b>Name and Province of Residence</b>	<b>Position with the Manager</b>	<b>Principal Occupation</b>	<b>Director/Officer Since</b>
William O. Ingram Alberta, Canada	President and Chief Executive Officer and Director	President and Chief Executive Officer, Rife Resources Ltd.	October 1, 1996
Darren G. Gunderson Alberta, Canada	Vice-President, Finance and Chief Financial Officer and Director	Vice-President, Finance and Chief Financial Officer, Rife Resources Ltd.	August 13, 2008
Garry W. Bieber Alberta, Canada	Vice-President, Production	Vice-President, Production, Rife Resources Ltd.	August 13, 2008
J. Frank George Alberta, Canada	Vice-President, Exploration	Vice-President, Exploration, Rife Resources Ltd.	October 1, 1996
Michael J. Stone Alberta, Canada	Vice-President, Land	Vice-President, Land Rife Resources Ltd.	March 1, 2010
Alan G. Glessing Alberta, Canada	Controller	Controller, Rife Resources Ltd.	August 13, 2008
Karen C. Taylor Alberta, Canada	Manager, Investor Relations and Corporate Secretary	Manager, Investor Relations and Corporate Secretary, Rife Resources Ltd.	February 27, 2008

As at March 16, 2011, the directors and senior officers of the Manager as a group beneficially owned, directly or indirectly, or exercised control or direction over 4,500 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 \$5.0 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 Resources, 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 15,234,470 Common Shares as at March 16, 2011, representing 25.61% 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 2010 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 a short form prospectus offering of Trust Units, which closed on December 10, 2009, the CN Pension Trust Funds acquired a pro rata share of the Trust Units issued pursuant to the offering being approximately 23% of the offering or 1,753,750 Trust Units at a price of \$15.15 per Trust Unit, which was the same price paid by all other purchasers.

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 Fees. 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 Fees 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 and January 1, 2011 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](http://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 March 23, 2011, which relates to the Annual Meeting of Shareholders to be held on May 11, 2011. Additional financial information is provided in the consolidated financial statements of the Corporation and Freehold Resources for the year ended December 31, 2010 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 – 4<sup>th</sup> 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, 2010. The reserves data are estimates of proved and proved plus probable reserves and related future net revenue as at December 31, 2010, 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 percent, included in the reserves data of the Corporation evaluated by us for the year ended December 31, 2010, 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, 2010 Dated January 19, 2011	Canada	0	\$656,232	0	\$656,232

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 16, 2011.

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

## APPENDIX B

### Form 51-101F3

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

Management of Freehold Royalties Ltd. (the "Corporation") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010 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 51-101 F1 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.

DATED as of this 16<sup>th</sup> day of March, 2011.

(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

## 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 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 with the external reserve evaluator at least once per year, in connection with the preparation of the year end reserves.

#### 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 the ceiling test calculation;
  - (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) recommend to the Board the appointment of external auditors;
    - (b) 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;
    - (c) 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
    - (d) 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.