# PENGROWTH ENERGY CORPORATION

## ANNUAL INFORMATION FORM

**For the year ended December 31, 2010**

**March 8, 2011**

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**Unless otherwise indicated, all of the information provided in this Annual Information Form is as at December 31, 2010.**

## GLOSSARY OF TERMS AND ABBREVIATIONS

The following terms in this Annual Information Form have the meanings set forth below:

**Corporate**

"**2003 Note Purchase Agreements**" means collectively, the separate and several note purchase agreements each dated April 23, 2003 among us, Pengrowth and the purchasers listed therein, as amended;

"**2003 US Senior Notes"** means the senior unsecured notes issued from time to time under the 2003 Note Purchase Agreements;

"**2005 Note Purchase Agreements**" means collectively, the separate and several note purchase agreements each dated December 1, 2005 among Pengrowth, the Trust and the purchasers listed therein, as amended;

"**2007 Note Purchase Agreements**" means collectively, the separate and several note purchase agreements each dated July 26, 2007 among us, Pengrowth and the purchasers listed therein, as amended;

"**2007 US Senior Notes**" means the senior unsecured notes issued from time to time under the 2007 Note Purchase Agreement;

"**2008 Note Purchase Agreements**" means collectively, the separate and several note purchase agreements dated August 21, 2008 among us, Pengrowth and the purchasers listed therein, as amended ;

"**2008 Senior Notes**" means the senior unsecured notes issued from time to time under the 2008 Note Purchase Agreements;

"**2010 Note Purchase Agreements**" means collectively, the separate and several note purchase agreements dated May 11, 2010 among us, Pengrowth and the purchasers listed therein, as amended;

"**2010 Senior Notes**" means the senior unsecured notes issued from time to time under the 2010 Note Purchase Agreements;

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

"**Arrangement**" means the plan of arrangement involving the Trust, Pengrowth Corporation, Esprit Energy Trust, Pengrowth Holding Trust, 1552168 Alberta Ltd., Monterey Exploration Ltd., the Corporation, the Unitholders and the holders of Exchangeable Shares completed on January 1, 2011 under the ABCA pursuant to which, the Trust converted from an income trust to a corporate structure;

"**Board**" or "**Board of Directors**" refers to our board of directors;

"**Common Shares**" means our common shares;

"**Corporation**" and "**Pengrowth**", "**we**", "**us**" **and** "**our**" refers to Pengrowth Energy Corporation and all of our wholly-owned direct and indirect subsidiary entities on a consolidated basis as well as our predecessors, Pengrowth Corporation and Pengrowth Energy Trust;

"**Credit Facility**" refers to Pengrowth's $1.0 billion extendible revolving term credit facility syndicated among ten financial institutions;

"**Exchangeable Shares**" means the series A exchangeable shares of Pengrowth Corporation;

"**Pengrowth Trust Indenture**" refers to the amended and restated trust indenture of the Trust dated July 1, 2009;

"**Shareholders**" means holders of Common Shares;

"**Trust**" refers to Pengrowth Energy Trust, a trust formed pursuant to the laws of Alberta pursuant to the Pengrowth Trust Indenture which was acquired by the Corporation on December 31, 2010 in connection with the Arrangement and subsequently wound up. All references to the "Trust", unless the context otherwise requires, are references to Pengrowth Energy Trust, its predecessors and subsidiaries;

"**Trust Units**" refers to the trust units of the Trust created and issued pursuant to the Pengrowth Trust Indenture;

"**UK Senior Notes**" means the senior unsecured notes issued from time to time under the 2005 Note Purchase Agreements; and

"**Unitholders**" refers to holders of Trust Units and class A trust units, as the context requires.

**Engineering**

"**Company Interest**" is equal to our gross interest plus Pengrowth's Royalty Interest; that is, the Working Interest share of production or reserves prior to the deduction of royalties plus any royalty interest in production or reserves at the wellhead;

"**Contingent Resources**" are those quantities of petroleum estimated, on a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. **Contingent Resources do not constitute, and should not be confused with, reserves**;

"**Developed Non-Producing Reserves**" refers to 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;

"**future net revenue**" refers to the estimated net amount to be received with respect to the development and production of reserves computed by deducting, from estimated future revenues, estimated future royalty obligations, costs related to the development and production of reserves and abandonment and reclamation costs (corporate general and administrative expenses and financing costs are not deducted);

"**GLJ**" refers to GLJ Petroleum Consultants Ltd., independent petroleum consultants, Calgary, Alberta;

"**GLJ Report**" refers to the report prepared by GLJ, dated March 7, 2011 with an effective date of December 31, 2010;

"**gross**" with respect to: (i) our interest in production or reserves, refers to our Working Interest share (operated or non-operated) before the deduction of royalties and without including any of our royalty interests; (ii) our wells, refers to the total number of wells in which we have an interest; and (iii) our properties, refers to the total area of properties in which we have an interest;

"**net**" with respect to: (i) our interest in production or reserves, refers to our Working Interest share (operated or non-operated) after the deduction of royalty obligations, plus our royalty interests in production or reserves; (ii) our interest in wells, refers to the number of wells obtained by aggregating our Working Interest in each of our gross wells; and (iii) our interest in a property, refers to the total area in which we have an interest multiplied by the Working Interest owned by us;

"**Possible Reserves**" are those additional reserves that are less certain to be recovered than Probable Reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated Proved plus Probable plus Possible Reserves;

"**Probable Reserves**" refers to 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;

"**Proved Developed Producing Reserves**" refers to those reserves 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;

"**Proved Developed Reserves**" or "**PDP**" refers to 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 to put the reserves on production; the developed category may be subdivided into Proved Developed Producing Reserves and Developed Non-Producing Reserves;

"**Proved Reserves**" or "**TP**" refers to 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;

"**Recycle Ratio**" refers to the ratio resulting from the quotient of operating netback and F&D or FD&A;

"**Remaining Reserve Life**" refers to the expected productive life of the property or fifty years, whichever is less;

"**Reserve Life Index**" or "**RLI**" refers to the number of years determined by dividing the Company Interest Reserves of a property by the 2011 Company Interest estimated production for the corresponding reserve category from such property. The reserves and the 2011 estimated production for such property come from the GLJ Report;

"**reserves**" refers to estimated remaining quantities of oil and natural gas and related substances anticipated to be recovered from known accumulations, from a given date forward, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions which are generally accepted as being reasonable and shall be disclosed; reserves are classified according to the degree of certainty associated with the estimate (e.g., proved, probable);

"**Royalty Interest**" refers to Pengrowth's interest in production and payment that is based on the gross production at the wellhead; a royalty is paid in either cash or kind, but is paid on a value calculated at the wellhead;

"**Total Proved Plus Probable Reserves**" or "**P+P**" means the aggregate of Proved Reserves and Probable Reserves;

"**Undeveloped Reserves**" refers to those reserves expected to be recovered from known accumulations where a significant expenditure (e.g. 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, possible) to which they are assigned; and

"**Working Interest**" refers to the percentage of undivided interest, excluding royalty interest, held by Pengrowth in an oil and gas property.

**<u>Abbreviations</u>**

"**Cdn$**" refers to Canadian dollars;

"**US$**" refers to United States dollars;

"**API**" refers to the American Petroleum Institute;

"$^{o}$**API**" refers to an indication of the specific gravity of crude oil measured on the API gravity scale;

"**bbl**", "**Mbbl**" and "**MMbbl**" refers to barrels, thousands of barrels and millions of barrels, respectively;

"**bblpd**" refers to barrels per day;

"**boe**", "**Mboe**" and "**MMboe**" refers to barrels of oil equivalent, thousands of barrels of oil equivalent and millions of barrels of oil equivalent, respectively, on the basis of one boe being equal to one barrel of oil or NGL or six Mcf of natural gas;

"**boepd**" refers to barrels of oil equivalent per day;

"**CBM**" refers to natural gas, primarily methane, producible from coal seams, commonly called coal bed methane;

"**CO2**" refers to carbon dioxide which is a gas at room temperature and pressure. However, at higher pressures, such as those used in EOR miscible floods, carbon dioxide is a liquid;

**"EOR"** refers to enhanced oil recovery;

"**EDGAR**" refers to the Electronic Data Gathering Analysis and Retrieval System maintained by the SEC;

"**GAAP**" or "**Canadian GAAP**" refers to generally accepted accounting principles in Canada;

"**F&D Costs**" refers to finding and development costs;

"**FD&A Costs**" refers to finding, development and acquisition costs;

"**$M**" and "**$MM**" refers to thousands of dollars and millions of dollars, respectively;

"**MMBtu**" refers to million British thermal units;

"**Mcf**", "**MMcf**" and "**Bcf**" refers to thousands of cubic feet, millions of cubic feet and billions of cubic feet, respectively;

"**Mcfe**" refers to thousand cubic feet of natural gas equivalent on the basis of one barrel of oil or one barrel of NGL being equal to six Mcf of natural gas;

"**Mcfpd**" and "**MMcfpd**" refers to thousands of cubic feet per day and millions of cubic feet per day, respectively;

"**NGL**" refers to natural gas liquids;

"**NYSE**" refers to the New York Stock Exchange;

"**SAGD**" refers to steam assisted gravity drainage;

"**SEC**" refers to the United States Securities and Exchange Commission;

"**SEDAR**" refers to the System for Electronic Document Analysis and Retrieval of the Canadian Securities Administrators;

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

"**TSX**" refers to the Toronto Stock Exchange;

"**WCSB**" refers to the Western Canadian Sedimentary Basin; and

"**WTI**" refers to West Texas Intermediate.

**Disclosure provided herein in respect of a boe and a Mcfe may be misleading, particularly if used in isolation. A boe conversation ratio of six Mcf of natural gas to one barrel of oil and a Mcfe conversion ratio of one barrel of oil to six Mcf of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**

## CONVERSION

In this Annual Information Form, measurements are given in standard imperial or metric units only. The following table sets forth certain standard conversions:

| To Convert From | To | Multiply by |
|---|---|---|
| Mcf | cubic metre | 28.174 |
| MMBtu | gigajoule | 1.0546 |
| cubic metre | bbl | 6.29 |
| metre | feet | 3.281 |
| mile | kilometre | 1.609 |
| hectare | acre | 2.471 |

## PRESENTATION OF OUR FINANCIAL INFORMATION

Financial information in this Annual Information Form has been prepared in accordance with Canadian GAAP. Canadian GAAP differs in some significant respects from United States generally accepted accounting principles and thus our financial statements may not be comparable to the financial statements of US companies. The principal differences as they apply to us are summarized in note 24 to our audited annual consolidated financial statements for the year ended December 31, 2010, which are available on the SEDAR website at www.sedar.com and in our current Form 40-F, which is available through EDGAR at the SEC's website at www.sec.gov.

Unless otherwise stated, all sums of money referred to in this Annual Information Form are expressed in Canadian dollars.

## PRESENTATION OF OUR RESERVE INFORMATION

National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**") of the Canadian Securities Administrators permits oil and gas issuers, in their filings with Canadian securities regulators, to disclose not only Proved Reserves but also Probable Reserves, Possible Reserves and Contingent Resources, and to disclose reserves and production on a gross basis before deducting royalties. Probable Reserves and Possible Reserves are of a higher risk and are less likely to be accurately estimated or recovered than Proved Reserves. Contingent Resources are higher risk than Probable Reserves and Possible Reserves and are less likely to be accurately estimated or recovered than Probable Reserves or Possible Reserves. Because we are permitted to prepare this Annual Information Form in accordance with Canadian disclosure requirements, we have disclosed in this Annual Information Form reserves designated as Probable Reserves, Possible Reserves and Contingent Resources and have disclosed reserves and production on a gross basis before deducting royalties.

Current SEC reporting requirements permit oil and gas companies to disclose probable and possible reserves, in addition to the required disclosure of proved reserves. If this Annual Information Form was required to be prepared in accordance with US disclosure requirements, the SEC's requirements would prohibit Contingent Resources from being disclosed. Under current SEC requirements, net quantities of reserves are required to be disclosed, which requires disclosure on an after royalties basis and does not include reserves relating to the interests of others. For a description of these and additional differences between Canadian and US standards of reporting reserves, see "*Risk Factors — Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States*". Additional information prepared in accordance with the US Financial Accounting Standards Board's Accounting Standards Update (Extractive Activities-Oil and Gas (Topic 932)) relating to our oil and gas reserves is set forth in our current Form 40-F, which is available through EDGAR at the SEC's website at www.sec.gov.

## FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements within the meaning of securities laws, including the "safe harbour" provisions of Canadian securities legislation and the United States *Private Securities Litigation Reform Act of 1995*. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "believe", "expect", "plan", "intend", "forecast", "target", "project", "guidance", "may", "will", "should", "could", "estimate", "predict" or similar words suggesting future outcomes or language suggesting an outlook. Forward-looking statements in this Annual Information Form include, but are not limited to: benefits and synergies resulting from our corporate and asset acquisitions, business strategy and strengths, goals, focus and the effects thereof, acquisition criteria, capital expenditures, reserves, resources, reserve life indices, estimated production, production additions from our 2011 development program, remaining producing reserves lives, operating expenses, asset retirement obligations, royalty rates, net present values of future net revenue from reserves, commodity prices and costs, dividend policy, exchange rates, the impact of contracts for commodities, development plans and programs, future development costs and the funding thereof, tax horizon, future income taxes, the impact of proposed changes to Canadian tax legislation or US tax legislation, abandonment and reclamation costs, government royalty rates (including estimated increase in royalties paid and estimated decline in net present value of reserves and 2011 cash flows) and expiring acreage. Statements relating to reserves and resources are forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described exist in the quantities predicted or estimated and can profitably be produced in the future.

Forward-looking statements and information are based on our current beliefs as well as assumptions made by, and information currently available to, us concerning anticipated financial performance, business prospects, strategies, regulatory developments, future oil and natural gas commodity prices and differentials between light, medium and heavy oil prices, future oil and natural gas production levels, future exchange rates, the proceeds of anticipated divestitures, the amount of future cash dividends paid by the Corporation, the cost of expanding our property holdings, our ability to obtain equipment in a timely manner to carry out development activities, our ability to market our oil and gas successfully to current and new customers, the impact of increasing competition, our ability to obtain financing on acceptable terms, and our ability to add production and reserves through our acquisition, development and exploration activities. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties, both general and specific, and risks that predictions, forecasts, projections and other forward-looking statements will not be achieved. We caution readers not to place undue reliance on these statements as a number of important factors could cause the actual results to differ materially from the beliefs, plans, objectives, expectations and anticipations, estimates and intentions expressed in such forward-looking statements. These factors include, but are not limited to: the volatility of oil and gas prices; production and development costs and capital expenditures; the imprecision of reserve estimates and estimates of recoverable quantities of oil, natural gas and liquids; unforeseen operating problems; pipeline or delivery constraints; our ability to replace and expand oil and gas reserves; environmental claims and liabilities; incorrect assessments of value when making acquisitions; increases in debt service charges; the loss of key personnel; the marketability of production; defaults by third party operators; unforeseen title defects; fluctuations in foreign currency and exchange rates; inadequate insurance coverage; counterparty risk; compliance with environmental laws and regulations; changes in tax and royalty laws; our ability to access external sources of debt and equity capital, the implementation of International Financial Reporting Standards ("**IFRS**"); and the implementation of greenhouse gas ("**GHG**") emissions legislation. Further information regarding these factors may be found under the heading *"Risk Factors"* in this Annual Information Form, under the heading *"Business Risks"* in our Management's Discussion and Analysis for the year ended December 31, 2010, and in our most recent consolidated financial statements, management information circular, quarterly reports, material change reports and news releases.

Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive. When relying on our forward-looking statements to make decisions with respect to Pengrowth, investors and others should carefully consider the foregoing factors and other uncertainties and potential events. Furthermore, the forward-looking statements contained in this Annual Information Form are made as of the date of this document and we do not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as required by applicable law. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement.

# PENGROWTH ENERGY CORPORATION

## Introduction

The Corporation is engaged in the development, production and acquisition of, and the exploration for, oil and natural gas reserves in the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia. The Corporation is the successor to the Trust, following the completion of the conversion of the Trust from an income trust to a corporate structure by way of a Court approved plan of arrangement under the ABCA which was completed on January 1, 2011. Pursuant to the Arrangement, on December 31, 2010, Unitholders of the Trust exchanged their Trust Units for Common Shares of the Corporation on a one for one (1:1) basis. At the same time, holders of Exchangeable Shares received 1.02308 Common Shares for each Exchangeable Share held. See "*General Development of the Business of the Corporation – Recent Developments*". Unless otherwise indicated, all information presented for the pre-Arrangement period in this Annual Information Form is that of the Trust.

The Corporation was originally incorporated pursuant to the ABCA on October 4, 2010, as 1562803 Alberta Ltd. and changed its name to Pengrowth Energy Corporation on December 2, 2010.

The head office and registered office of the Corporation is located at 2100, 222 – 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0B4.

## General Development of the Business

*Recent Developments*

On January 1, 2011 the Corporation completed the Arrangement, pursuant to which the Trust converted into a corporate structure.

*Three Year Historical Overview*

*2010*

On November 9, 2010, we released the details of our 2011 capital expenditure program and provided guidance on production and operating costs for 2011. Our 2011 development capital expenditure program is expected to be $400 million. We will continue to monitor and adjust capital investment levels in order to ensure that we optimize value, operate within our cash flow and have the flexibility to take advantage of acquisition opportunities.

On September 15, 2010, the Trust completed the acquisition of Monterey Exploration Ltd. ("**Monterey**") for total consideration of approximately $445 million (including $82 million for shares already owned), comprised of 27,967,959 Trust Units, 4,994,426 Exchangeable Shares and $41.8 million of assumed debt. No business acquisition report (Form 51-102F4) was required or filed in respect of this acquisition.

On May 11, 2010, Pengrowth Corporation closed a US$187 million offering of the 2010 Senior Notes. The notes were issued in two series; US$71.5 million of 4.67 percent notes due in 2015 and US$115.5 million of 5.98 percent notes due in 2020 (together, the 2010 Senior Notes).

On January 14, 2010, certain outstanding debentures were redeemed at a cash redemption price of $1,025 per $1,000 principal value for a total cost of $76,609,525, plus accrued and unpaid interest to the redemption date. The cash redemption amount was funded with incremental borrowings from the Credit Facility.

*2009*

On November 11, 2009, we announced the appointment of John B. Zaozirny as Chairman of the Board of Pengrowth Corporation.

On October 23, 2009, Pengrowth Corporation completed a bought deal public offering of 28,847,000 Trust Units at $10.40 per Trust Unit for total gross proceeds of approximately $300 million.

On September 13, 2009 Derek W. Evans was appointed President and Chief Executive Officer of Pengrowth Corporation. Mr. Evans' appointment as Chief Executive Officer followed the retirement of James S. Kinnear as Chairman and Chief Executive Officer.

Prior to June 30, 2009, the Trust and Pengrowth Corporation were managed by Pengrowth Management Limited pursuant to a third party management agreement (the "**Management Agreement**"). On June 30, 2009, the Management Agreement expired and management of the Trust and Pengrowth Corporation was internalized.

On May 25, 2009 Derek W. Evans was appointed as the President and Chief Operating Officer and as a director of Pengrowth Corporation.

*2008*

On September 30, 2008, we closed the acquisition of Accrete Energy Inc. for total consideration of $120 million paid by the issuance of 4,973,325 Trust Units and the assumption of $22 million of Accrete's net liabilities. Pursuant to the acquisition, we acquired 1,900 boepd of production in the Harmattan gas field and 8.4 MMboe of P+P Company Interest reserves as of the closing date of September 30, 2008.

On August 21, 2008, we completed a US$265 million private placement of 6.98 percent senior unsecured ten year notes to a group of US investors, and a $15 million private placement of 6.61 percent senior unsecured ten year notes to a group of Canadian investors (together, the "**2008 Senior Notes**"). Interest on these notes is payable semi-annually.

# DESCRIPTION OF OUR BUSINESS

## General

We are engaged in the development, production and acquisition of, and the exploration for, oil and natural gas reserves in the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia. Our long term goal is to maximize value creation for the benefit of our Shareholders. Our competitive position is dependent on our ability to execute our business strategy. We believe we have the skills and financial capacity to develop our opportunities. A key factor affecting our finances is commodity prices over which we have no control.

Over the long term, we target a balance of capital spending that can maintain or modestly grow production and reserves on a debt adjusted share basis. This will be achieved through a combination of:

- focusing capital expenditures on existing low cost, low risk plays (Carson Creek, Swan Hills, Groundbirch, Olds Garrington) as well as to identify, test and develop other resource plays where repeatable, predictable and scalable results can be achieved;
- investing capital to advance the long term value of our resource plays (Lindbergh and EOR opportunities);
- acquiring other assets in the WCSB with low cost, low risk, repeatable, predictable and scalable drilling opportunities;
- maintaining appropriate debt levels; and
- ensuring a high level of capital efficiency and cost discipline.

As at December 31, 2010, we had 582 permanent employees.

## Business Strategy

Our goal is to maximize value creation for Shareholders through reinvesting a portion of our cash flow on our oil and gas properties while continuing to pay dividends. In October 2009, the Trust's business model was changed to increase the emphasis on capital reinvestment following a review of the best opportunities for value creation on the Trust's existing asset base. This value creation strategy has been implemented and further developed throughout 2010.

Our capital program focuses on our short and medium term inventory of low cost, low risk, repeatable and scalable resource plays that have the ability to enhance reserves and production. We aim to continue acquiring companies and assets and anticipate financing those acquisitions with a prudent combination of debt and equity.

Our operational expertise is in the WCSB. We rely on our expertise to partially offset production declines in our mature oil and gas properties as well as develop new production in less mature oil and gas properties. We have an advantage through our expertise in horizontal well carbonate reef multi-stage fracturing technology, EOR technologies and waterflood optimization. Our inventory of undeveloped land and opportunities on our properties provide future drilling opportunities for the short-term and mid-term. In the mid-term, we anticipate continuing to develop the Montney reservoir at the Groundbirch property and, receiving regulatory approval for a pilot project at our Lindbergh SAGD project with potential for a commercial project providing long term development potential. The development of CO2 EOR at a number of fields with the initial development at Judy Creek and the Horn River shale gas property also factor into our medium term plans.

For 2011, we have established a prudent capital spending level that is higher than the previous year, but flexible in an uncertain commodity price environment. We prioritize our capital investments based on:

- recycle ratio;

- net present value of future cash flow as compared to the capital invested;
- rate of return of future cash flows;
- potential for continued, repeatable and scalable development; and
- investments necessary to maintain existing facilities and wells.

## PENGROWTH – OPERATIONAL INFORMATION

### Principal Properties

The portfolio of properties acquired and held by us reflects a mix of conventional and unconventional assets. While traditionally the Trust acquired properties and developed them, our shift in strategy as announced in October 2009 to become a low cost, low risk, repeatable and scalable resource play developer has begun to return results as demonstrated by our improved 2010 F&D Costs.

The following table summarizes our principal producing properties as of December 31, 2010 based on the GLJ Report using forecast prices and costs. The following table utilizes data from the GLJ Report in respect of our oil and gas properties effective December 31, 2010. The table also contains our average daily production of oil, natural gas and NGL for the year ended December 31, 2010.

**Summary of Company Interest at December 31, 2010[(1)] (Forecast Prices and Costs)[(2)]**

| Field | P+P Reserves Mboe | Remaining Reserve Life years | P+P Reserve Life Index years | P+P Value Before Tax at 10% DR[(4)] $MM | 2010 Oil Production bblpd | 2010 Gas Production MMcfd | 2010 NGL Production bblpd | 2010 Total Production boepd[(5)] |
|---|---|---|---|---|---|---|---|---|
| Judy Creek | 32,579 | 50 | 11.9 | 729.1 | 5,939 | 5.3 | 1,444 | 8,258 |
| Groundbirch | 27,158 | 46 | 18.5 | 187.2 | - | 0.7 | - | 122 |
| Carson Creek | 23,990 | 44 | 8.0 | 454.5 | 1,880 | 13.7 | 2,246 | 6,413 |
| Weyburn Unit | 21,261 | 47 | 21.8 | 438.7 | 2,550 | 0.3 | - | 2,604 |
| Harmattan | 16,718 | 50 | 7.6 | 195.8 | 412 | 18.4 | 1,642 | 5,117 |
| Swan Hills Unit | 16,157 | 50 | 17.8 | 234.2 | 1,814 | 1.7 | 243 | 2,343 |
| Olds | 16,014 | 50 | 12.6 | 161.8 | 13 | 17.2 | 708 | 3,587 |
| Twining | 11,635 | 50 | 11.2 | 171.9 | 592 | 13.4 | 400 | 3,228 |
| CBM | 11,065 | 47 | 16.8 | 85.9 | - | 11.4 | 2 | 1,898 |
| **Subtotal** | **176,577** | **50** | **12.4** | **2,659.1** | **13,200** | **82.1** | **6,685** | **33,570** |
| Remainder[(3)] | 141,852 | 50 | 9.8 | 1,977.3 | 15,331 | 137.2 | 2,926 | 41,125 |
| **Total** | **318,429** | **50** | **11.1** | **4,636.4** | **28,531** | **219.3** | **9,611** | **74,695** |

**Notes:**

(1) 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.

(2) Forecast prices are shown under the heading *"Pricing Assumptions"*.

(3) "Remainder" includes our Working Interests and Royalty Interests in approximately 125 other properties.

(4) Estimated future net revenues disclosed do not represent fair market value.

(5) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

*Judy Creek*

We have a 100 percent Working Interest in both the Judy Creek Beaverhill Lake Unit and the Judy Creek West Beaverhill Lake Unit (oil properties together referred to as "**Judy Creek**"). We also have a 54.4 percent Working Interest in and operate the Judy Creek Gas Conservation Plant that services a number of other properties in the area including Swan Hills, Virginia Hills and South Swan Hills. Judy Creek is located approximately 200 kilometres northwest of Edmonton, Alberta and covers an area of approximately 38,300 acres. Judy Creek was discovered in 1959, placed on waterflood in 1962 and hydrocarbon miscible flood in 1985. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2010 are estimated to be 32.6 MMboe. The Remaining Reserve Life is 50 years and the P+P Reserve Life Index is 11.9 years. Our Company Interest production for Judy Creek averaged 8,258 boepd in 2010.

*2010 Development Activity*

Two horizontal multi-stage acid fractured wells were drilled to test two play concepts: the underlying platform and the capping shoal of the Beaverhill Lake ("**BHL**") formation. Combined rate at year-end from the two wells was 360 boepd. Two vertical producers were reactivated and a vertical well was acid fractured resulting in a combined rate at year-end from those three wells of 100 boepd. A new horizontal miscible flood injector was drilled and placed in service and a new vertical producer was drilled as part of the new injection pattern.

*2011 Development Activity*

The 2011 capital program includes the drilling and multi-staged acid fracture completion of approximately ten BHL horizontal wells. Most of this activity is expected to occur in the first half of 2011. Six of the wells are planned to be drilled in the BHL Platform in the northeast area of the Judy Creek BHL Unit. Three wells are planned to be drilled at the southern end of the Judy Creek West BHL Pool targeting the uppermost reef stage. One well will be drilled in the reef interior.

*Carbon Dioxide (CO2) EOR Pilot*

The intent of the Judy Creek CO2 EOR pilot project is to evaluate the potential of a commercial sized CO2 miscible flood that would increase oil recovery and recover hydrocarbons left behind from the hydrocarbon miscible flood. CO2 injection into the first pilot commenced in February of 2007 and ended June 2009.

Since February 2007, 1.2 Bcf of CO2 has been injected into the 80 acre pilot pattern resulting in an additional 59 Mbbl of oil and 224 MMcf of natural gas being recovered. The results of the pilot are in-line or better than our internal estimates and can be used to extrapolate the additional recoveries across our whole field. Although CO2 injection has ended, the increased production is expected to continue and monitoring recovery will be maintained into 2011.

*Groundbirch*

We have an average 90 percent Working Interest in the Groundbirch properties we acquired in September 2010 from Monterey Exploration Ltd. The Montney formation, one of the most economic gas resource plays in North America, is present across our Groundbirch property which is located approximately 40 kilometres southwest of Ft. St. John, British Columbia and covers an area of approximately 13,440 acres. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2010 are estimated to be 27.2 MMboe. The Remaining Reserve Life is 46 years and the P+P Reserve Life Index is 18.5 years. Our Company Interest production for Groundbirch averaged only 122 boepd in 2010 as the gas plant was only placed in operation on December 18, 2010.

*2010 Development Activity*

Since acquiring Monterey on September 15, 2010 and before December 31, 2010, three horizontal Montney gas wells have been drilled, five horizontal Montney wells have been multi-stage fractured, a 28 MMcfpd gas plant was constructed and commissioned, and approximately 15 km of pipe was installed. By the end of December 2010, the gas plant was operating with gas being supplied from five wells on our Groundbirch lands.

*2011 Development Activity*

The 2011 capital program includes further development of the Montney gas resource through three more horizontal drills, and a total of eight Montney horizontal wells being multi-stage fractured. A vertical well will test the Doig production formation and, if warranted, a horizontal well will be drilled and completed in the Doig later in 2011. The 2011 development plan is designed to keep the gas plant operating near design capacity.

*Carson Creek*

Carson Creek is located 160 kilometres northwest of Edmonton, Alberta and is comprised of two Pengrowth-operated units (one oil unit and one natural gas and gas condensate unit) covering approximately 46,200 acres.

The Carson Creek North Beaverhill Lake Unit No. 1 (oil), in which we have an 88.6 percent Working Interest, was discovered in 1958 and the current waterflood was initiated in 1964.

The Carson Creek Beaverhill Lake Unit No. 1 (gas and gas condensate), in which we have a 95.1 percent Working Interest, was discovered in 1958. From 1962 to 1985, a re-cycling program was operated in which NGL were stripped from the liquid-rich natural gas and the remaining lean gas re-injected. Gas re-injection now only occurs during plant disruption.

Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2010 are estimated to be 24.0 MMboe. The Remaining Reserve Life is 44 years and the P+P Reserve Life Index is 8 years. Our Company Interest production for Carson Creek averaged 6,413 boepd in 2010.

We have a 95.1 percent Working Interest in the Carson Creek gas plant, which processes the gas production.

*2010 Development Activity*

Our 2010 activity consisted of drilling seven horizontal wells in the Carson Creek Beaverhill Lake Unit No. 1. This activity built on the successful horizontal well developmental program in the new “C” pool that started in 2009. All wells were multi-staged acid fractured. A total of 16 horizontal wells are currently producing from the “C” pool and have an average liquid yield of over 200 bbl of NGL per MMcf. Note that the original wells that had undergone re-cycling have a yield near 35 bbl of NGL per MMcf.

Our 2010 activities in the Carson Creek North Unit included waterflood optimization and well workovers to increase production and improve recovery.

*2011 Development Activity*

We will continue with waterflood optimization, injector stimulations and a water injector conversion in 2011. One new horizontal well is planned to be drilled.

In the Carson Creek Beaverhill Lake Unit No. 1 and surrounding areas, more drilling is planned for 2011. Six new horizontal drills have been budgeted for a program starting in the first half of the year.

*Weyburn Unit*

The Weyburn Unit is located in southeastern Saskatchewan. We hold a 9.76 percent Working Interest in this unit which is operated by a senior producer. The unit produces medium sour crude oil (25 to 34° API) from the Midale carbonate reservoir under waterflood and CO2 EOR miscible flood. The field consists of approximately 700 production wells and 300 injection wells. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2010 are estimated to be 21.3 MMboe. The Remaining Reserve Life is 47 years and the P+P Reserve Life Index is 21.8 years. Our Company Interest production for Weyburn averaged 2,604 boepd in 2010.

*2010 Development Activity*

In 2010, an average of 10.2 MMcfpd of CO2 was purchased for EOR injection to supplement the CO2 that is separated from oil production. Total injection rates reached 24 MMcfpd on peak days. In 2010, 32 gross wells were drilled: two were production wells, 28 were injectors and two were observation wells. The replacement of the low pressure gas compressor that was initiated in 2010 is to be completed in 2011.

*2011 Development Activity*

The 2011 program includes purchasing an average 11.6 MMcfpd of CO2 for EOR injection. Current plans are to drill eleven new wells as part of expanding the CO2 EOR and waterflood patterns.

*Harmattan*

The Harmattan gas field is located approximately 90 kilometres northwest of Calgary, Alberta. It is comprised of wells and pools in formations from the Cardium to the Wabumun, as well as two partner-operated Elkton units. The production is predominantly sweet liquids-rich natural gas and sweet oil with Working Interests averaging 55 percent in the non-unit lands (operated) and 25 percent in the partner-operated units. The Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2010 are estimated to be 16.7 MMboe. The Remaining Reserve Life is 50 years and the P+P Reserve Life Index is 7.6 years. Our Company Interest production for Harmattan averaged 5,117 boepd in 2010.

*2010 Development Activity*

We drilled two successful Elkton wells early in the year. These wells are liquid-rich gas wells, producing approximately 75 bbl of NGL per MMcf. The success of these two original wells led to two more wells being drilled in the fourth quarter. One started production in November and the other well will begin production in the first quarter of 2011.

We drilled four Cardium formation wells in 2010 to test the Cardium potential on our lands. We had varied success with the most recent well’s initial production rate was over 350 boepd while others had lower rates.

Three Viking formation proof of concept wells were drilled in 2010. A fourth well was junked and abandoned earlier in the year due to hole conditions. Initial indications from the program are quite positive and the results will be evaluated to define future development.

*2011 Development Activity*

At least two more Elkton formation wells are expected to be drilled as a continuation of the 2010 program. One or two wells are planned to be drilled into the Cardium formation targeting areas with good off-setting production. The performance of the three 2010 Viking formation wells will help to determine Viking formation drilling plans later in 2011.

<u>*Swan Hills Unit*</u>

The Swan Hills Unit No. 1 is located near the Judy Creek field in north central Alberta. We hold a 24.01 percent Working Interest in this unit which is operated by our partner. Light sweet crude oil is produced from the Beaverhill Lake reservoir which has a waterflood and a hydrocarbon miscible flood EOR program. The remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2010 are estimated to be 16.2 MMboe. The Remaining Reserve Life is 50 years and the P+P Reserve Life Index is 17.8 years. Our Company Interest production for Swan Hills averaged 2,343 boepd in 2010.

*2010 Development Activity*

In 2010, four new producing wells were drilled with initial rates ranging from 20 to 260 bblpd of oil.

*2011 Development Activity*

The 2011 capital program for production development includes drilling four gross producing wells as well as conducting eight workovers on existing wells to stimulate new production and to add recoverable reserves.

<u>*Olds*</u>

The Olds property is located 95 kilometres north of Calgary, Alberta. Our interests include 100 percent ownership in the Olds Gas Field Unit No. 1. In addition, we have a 75 percent average Working Interest in non-unit reserves. The Olds unit produces sour natural gas from the Wabamun Formation, with $H_2S$ concentrations ranging from less than one to 35 percent. The non-unit reserves are contained within formations from the Wabamun to the Edmonton group, and are predominantly sweet natural gas. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2010 are estimated to be 16.0 MMboe. The Remaining Reserve Life is 50 years and the P+P Reserve Life Index is 12.6 years. Our Company Interest production for Olds averaged 3,587 boepd in 2010.

We operate and own 100 percent of the sour gas processing plant at Olds, which processes both our production and third party volumes. Third party volumes represent approximately 35 percent of the total volumes processed.

*2010 Development Activity*

In 2010, we multi-stage fractured one existing Wabamun gas well. The production increased four-fold immediately following the operation. The well now produces at 1.5 times pre-fracture rates. Further projects have been delayed due to the current low gas price environment.

*2011 Development Activity*

We anticipate continued well optimization work as well as up to three recompletions using the multi-stage fracturing techniques in existing wellbores.

<u>*Twining*</u>

The Twining property is located approximately 130 kilometres northeast of Calgary, Alberta. Although production is mainly gas, there is also oil production from this area. We operate the majority of the production within this property. Oil is produced from the Pekisko formation. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2010 are estimated to be 11.6 MMboe. The Remaining Reserve Life is 50 years and the P+P Reserve Life Index is 11.2 years. Our Company Interest production for Twining averaged 3,228 boepd in 2010.

*2010 Development Activity*

Our 2010 activity included drilling two horizontal Pekisko oil wells, and recompleting an existing horizontal oil well using multi-stage fracturing technology.

*2011 Development Activity*

Plans for 2011 development activity include multi-stage fracturing one of the 2010 Pekisko horizontal drills, drilling two additional horizontal Pekisko oil wells, along with multi-stage fracturing an existing producing Pekisko oil well.

*Coal Bed Methane (CBM)*

Our CBM activity is focused in the Elnora, Fenn Big Valley and Twining areas which are 100 to 160 kilometres northeast of Calgary, Alberta. Remaining Company Interest Total Proved Plus Probable Reserves at December 31, 2010 are estimated to be 11.1 MMboe. The Remaining Reserve Life is 50 years and the P+P Reserve Life Index is 11.2 years. Our Company Interest CBM production averaged 1,898 boepd in 2010.

*2010 Development Activity*

Our 2010 activity included drilling 19 gross (13.1 net) wells. These wells were drilled to hold expiring lands and to evaluate the viability of higher well densities in our core areas.

Partners also drilled nine gross (one net) wells in 2010.

*2011 Development Activity*

In 2011, we anticipate completing three wells that were drilled late in 2010 on expiring lands. Low gas price forecasts will limit our 2011 investment in CBM development activities.

## Statement of Oil and Gas Reserves and Reserves Data

*Disclosure of Reserves Data*

The information in this section is based upon an evaluation by GLJ, prepared in accordance with NI 51-101, with an effective date of December 31, 2010 contained in the GLJ Report, with the exception of information relating to income tax and the after tax future net revenues associated with our reserves, which we determined. The effective date of the information in this section is December 31, 2010 and the preparation date is January 19, 2011 when the final information was provided. The information in this section summarizes our oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using GLJ's forecast prices and costs and constant prices and costs. We engaged GLJ to provide an independent evaluation of Proved Reserves and Total Proved Plus Probable Reserves and no attempt was made to evaluate Possible Reserves in the conventional properties. It is our practice to obtain an engineering report evaluating all of our Proved Reserves and Probable Reserves as at December 31 of each year. Only in respect of the Lindbergh oil sands property and the Groundbirch natural gas property did GLJ evaluate Possible Reserves and Contingent Resources. All of our reserves are in Canada in the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia. In certain instances in this Annual Information Form, we have presented estimates of reserves, future net revenue and Contingent Resources for individual properties. The estimates of reserves, future net revenue and Contingent Resources for individual properties may not reflect the same confidence level as estimates of reserves, future net revenue and Contingent Resources for all properties, due to the effects of aggregation.

The following tables set forth certain information relating to our oil and natural gas reserves and the net present value of the estimated future net revenue associated with such reserves as at December 31, 2010 contained in the GLJ Report. These tables summarize the data contained in the GLJ Report, and, as a result, may contain slightly different numbers than the GLJ Report due to rounding. Columns may not add due to rounding.

For the purposes of this Annual Information Form, the Probable Reserves reported for the Lindbergh oil sands property in the GLJ Report are included with the Heavy Oil reserves. See – "*Lindbergh Oil Sands Reserves and Contingent Resources*".

Our future net revenues associated with the production and reserves contained in this Annual Information Form reflect the royalty programs in-place on December 31, 2010.

The information set forth below is derived from the GLJ Report, which has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation ("**COGE**") Handbook and the reserves definitions contained in NI 51-101 and the Canadian Oil and Gas Evaluation Handbook. The GLJ Report incorporates estimates of future well abandonment obligations but does not include estimates of remediation costs. **The GLJ forecasts of future net revenue are stated prior to any provision for income taxes, interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. The estimated future net revenue shown below does not represent the fair market value of the properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and estimates of crude oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL and natural gas reserves may be greater than or less than the estimates provided herein.**

We determined the future net revenue and present value of future net revenue after income taxes by utilizing GLJ's before income tax future net revenue and our estimate of income tax. Our estimate of cash income tax makes use of the following assumptions:

- Corporate income tax at the current legislated rate;

- Annual general and administrative expenses at the current rate;
- Interest expense at the current rate;
- Tax pool deductions utilizing our existing $3.0 billion of tax pools and forecasted additions to our tax pools from capital expenditures as forecast by GLJ; and
- Any such other additional deductions and adjustments as is and would be consistent with the manner in which we file and would file future tax returns.

The net revenues estimated in the GLJ Report represent estimates of the revenues from oil and gas sales from our petroleum and natural gas properties together with an estimate of processing revenues less royalties (net of incentives), mineral taxes, field operating expenses and capital obligations. These net revenues are not the same as cash flows from operating activities reported by the Corporation in our statement of cash flows. The GLJ Report does not estimate general and administrative expenses and interest.

We have not paid cash income tax in the past year and based upon current tax legislation, anticipated capital spending and economic conditions, we do not anticipate paying income tax until after 2014.

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

*Reserves Data (Forecast Prices and Costs)*

**Summary of Oil and Gas Reserves**
**as of December 31, 2010**
**(Forecast Prices and Costs)[(1)]**

| | Light and Medium Oil | | | Heavy Oil[(2)] | | | Natural Gas Liquids | | |
|---|---|---|---|---|---|---|---|---|---|
| **Reserves Category** | **Company Interest** (Mbbl) | **Gross Interest** (Mbbl) | **Net Interest** (Mbbl) | **Company Interest** (Mbbl) | **Gross Interest** (Mbbl) | **Net Interest** (Mbbl) | **Company Interest** (Mbbl) | **Gross Interest** (Mbbl) | **Net Interest** (Mbbl) |
| **Proved Reserves** | | | | | | | | | |
| Proved Developed Producing | 63,893 | 63,750 | 50,755 | 13,505 | 13,499 | 11,658 | 19,655 | 19,618 | 14,089 |
| Proved Developed Non-Producing | 2,251 | 2,250 | 1,699 | - | - | - | 721 | 721 | 539 |
| Proved Undeveloped | 15,085 | 15,077 | 11,631 | 1,732 | 1,732 | 1,457 | 878 | 878 | 662 |
| **Total Proved Reserves** | **81,228** | **81,077** | **64,085** | **15,238** | **15,232** | **13,114** | **21,254** | **21,216** | **15,290** |
| Probable Reserves | 29,069 | 29,024 | 22,345 | 11,234 | 11,233 | 9,780 | 8,227 | 8,216 | 6,130 |
| **Total Proved Plus Probable Reserves** | **110,297** | **110,101** | **86,430** | **26,472** | **26,465** | **22,894** | **29,481** | **29,432** | **21,420** |

| | Natural Gas | | | Coal Bed Methane | | | Total Oil Equivalent Basis[(3)] | | |
|---|---|---|---|---|---|---|---|---|---|
| **Reserves Category** | **Company Interest** (MMcf) | **Gross Interest** (MMcf) | **Net Interest** (MMcf) | **Company Interest** (MMcf) | **Gross Interest** (MMcf) | **Net Interest** (MMcf) | **Company Interest** (Mboe) | **Gross Interest** (Mboe) | **Net Interest** (Mboe) |
| **Proved Reserves** | | | | | | | | | |
| Proved Developed Producing | 493,650 | 491,062 | 421,501 | 26,012 | 25,699 | 24,124 | 183,664 | 182,995 | 150,772 |
| Proved Developed Non-Producing | 21,374 | 21,258 | 17,274 | 2,039 | 2,026 | 1,724 | 6,874 | 6,851 | 5,405 |
| Proved Undeveloped | 51,742 | 51,742 | 45,128 | 25,026 | 24,955 | 21,413 | 30,489 | 30,470 | 24,839 |
| **Total Proved Reserves** | **566,767** | **564,062** | **483,903** | **53,077** | **52,680** | **47,261** | **221,028** | **220,316** | **181,016** |
| Probable Reserves | 280,262 | 279,489 | 238,563 | 12,966 | 12,866 | 11,639 | 97,402 | 97,199 | 79,956 |
| **Total Proved Plus Probable Reserves** | **847,029** | **843,551** | **722,466** | **66,043** | **65,547** | **58,900** | **318,429** | **317,514** | **260,972** |

**Notes:**

(1) Forecast prices are shown under the heading *"Pricing Assumptions"*.

(2) Includes 6,348 Mbbl of Company Interest heavy oil Probable Reserves for the Lindbergh oil sands property in the GLJ Report.

(3) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

## Summary of Net Present Value of Future Net Revenue as of December 31, 2010 Before and After Income Taxes (Forecast Prices and Costs)[1]

| | Before Income Taxes Discounted at (%/Year) | | | | | Unit Value Before Income Tax Discounted at 10%/Year[2] [3] | |
|---|---|---|---|---|---|---|---|
| **Reserves Category** | **0%** ($MM) | **5%** ($MM) | **10%** ($MM) | **15%** ($MM) | **20%** ($MM) | $/boe | $/Mcfe |
| **Proved Reserves** | | | | | | | |
| Proved Developed Producing | 5,338 | 3,945 | 3,143 | 2,626 | 2,267 | 20.84 | 3.47 |
| Proved Developed Non-Producing | 197 | 123 | 86 | 64 | 50 | 15.83 | 2.64 |
| Proved Undeveloped | 994 | 551 | 325 | 198 | 120 | 13.07 | 2.18 |
| **Total Proved Reserves** | **6,530** | **4,618** | **3,553** | **2,887** | **2,437** | **19.63** | **3.27** |
| Probable Reserves | 3,396 | 1,769 | 1,084 | 732 | 526 | 13.55 | 2.26 |
| **Total Proved Plus Probable Reserves** | **9,926** | **6,387** | **4,636** | **3,620** | **2,963** | **17.77** | **2.96** |

| | After Income Taxes Discounted at (%/Year)[4] | | | | |
|---|---|---|---|---|---|
| **Reserves Category** | **0%** ($MM) | **5%** ($MM) | **10%** ($MM) | **15%** ($MM) | **20%** ($MM) |
| **Proved Reserves** | | | | | |
| Proved Developed Producing | 4,813 | 3,680 | 2,931 | 2,414 | 2,043 |
| Proved Developed Non-Producing | 139 | 90 | 62 | 45 | 33 |
| Proved Undeveloped | 730 | 402 | 226 | 126 | 67 |
| **Total Proved Reserves** | **5,681** | **4,172** | **3,218** | **2,584** | **2,143** |
| Probable Reserves | 2,559 | 1,384 | 810 | 510 | 343 |
| **Total Proved Plus Probable Reserves** | **8,240** | **5,556** | **4,028** | **3,094** | **2,486** |

### Notes:

(1) Forecast prices are shown under the heading *"Pricing Assumptions"*.

(2) Net present value of future net revenue per reserve unit values are based on our net reserves.

(3) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil. Oil has been converted to thousand cubic feet of natural gas equivalent on the basis of one barrel of oil being equal to six Mcf of natural gas.

(4) After tax values were calculated using current corporate tax rates, existing tax pools and additions to the tax pools through capital expenditures as forecast by GLJ. See – "*Statement of Oil and Gas Reserves and Reserves Data – Disclosure of Reserves Data*" for additional descriptions of the assumptions made in calculating the after tax values.

## Additional Information Concerning Future Net Revenue (undiscounted) as of December 31, 2010 (Forecast Prices and Costs)[1]

| Reserves Category | Revenue ($MM) | Royalties[2] ($MM) | Operating Costs ($MM) | Development Costs ($MM) | Abandonment Costs[3] ($MM) | Future Net Revenue Before Income Taxes ($MM) | Income Tax ($MM) | Future Net Revenue After Income Taxes ($MM) |
|---|---|---|---|---|---|---|---|---|
| Proved Reserves | 15,054 | 2,908 | 4,768 | 603 | 246 | 6,530 | 849 | 5,681 |
| Total Proved Plus Probable Reserves | 22,413 | 4,344 | 6,788 | 1,079 | 277 | 9,926 | 1,686 | 8,240 |

**Notes:**

(1) Forecast prices are shown under the heading *"Pricing Assumptions"*.

(2) Crown royalties payable to the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia and any freehold and over-riding royalties payable. This includes the impact of the New Royalty Framework implemented by the Government of Alberta on January 1, 2009, the optional Transitional Royalty and any drilling incentive programs currently in effect.

(3) Includes GLJ's estimate of well abandonment costs and abandonment of Sable Island facilities and subsea pipelines, but does not include abandonment costs for other facilities or any surface reclamation costs. See "*Pengrowth – Operational Information – Additional Information Concerning Abandonment & Reclamation Costs*".

## Net Present Value of Future Net Revenue By Production Group as of December 31, 2010 (Forecast Prices and Costs)[1]

| Reserves Category | Production Group | Future Net Revenue Before Income Taxes (discounted at 10%/yr) ($MM) | Unit Value[4][5] ($/boe) | Unit Value[4][5] ($/Mcfe) |
|---|---|---|---|---|
| Total Proved Reserves | Light and Medium Crude Oil (including solution gas and other by-products)[2] | 2,017 | 25.50 | 4.25 |
| | Heavy Oil (including solution gas and other by-products)[2] | 380 | 25.92 | 4.32 |
| | Natural Gas (including by-products but excluding solution gas from oil wells)[3] | 1,087 | 13.70 | 2.28 |
| | Non-conventional Oil & Gas Activities | 68 | 8.61 | 1.43 |
| | **Total** | **3,553** | **19.63** | **3.27** |
| Total Proved Plus Probable Reserves | Light and Medium Crude Oil (including solution gas and other by-products)[2] | 2,540 | 23.83 | 3.97 |
| | Heavy Oil (including solution gas and other by-products)[2] | 492 | 19.72 | 3.29 |
| | Natural Gas (including by-products but excluding solution gas from oil wells)[3] | 1,517 | 12.69 | 2.11 |
| | Non-conventional Oil & Gas Activities | 87 | 8.84 | 1.47 |
| | **Total** | **4,636** | **17.77** | **2.96** |

**Notes:**

(1) Forecast prices are shown under the heading *"Pricing Assumptions"*.

(2) NGL associated with the production of solution gas are included as a by-product.

(3) NGL associated with the production of natural gas are included as a by-product.

(4) Net present value of future net revenue per boe or Mcfe are based on our net reserves.

(5) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil. Oil has been converted to thousand cubic feet of natural gas equivalent on the basis of one barrel of oil being equal to six Mcf of natural gas.

*Reserves Data (Constant Prices and Costs)*

## Summary of Oil And Gas Reserves
## as of December 31, 2010
## (Constant Prices and Costs)[(1)]

| Reserves Category | Light and Medium Oil | | | Heavy Oil[(2)] | | | Natural Gas Liquids | | |
|---|---|---|---|---|---|---|---|---|---|
| | Company Interest (Mbbl) | Gross Interest (Mbbl) | Net Interest (Mbbl) | Company Interest (Mbbl) | Gross Interest (Mbbl) | Net Interest (Mbbl) | Company Interest (Mbbl) | Gross Interest (Mbbl) | Net Interest (Mbbl) |
| **Proved Reserves** | | | | | | | | | |
| Proved Developed Producing | 63,559 | 63,421 | 53,513 | 13,413 | 13,408 | 11,785 | 19,121 | 19,087 | 13,702 |
| Proved Developed Non-Producing | 2,250 | 2,248 | 1,760 | - | - | - | 767 | 766 | 579 |
| Proved Undeveloped | 15,085 | 15,077 | 12,255 | 1,730 | 1,730 | 1,498 | 872 | 872 | 660 |
| **Total Proved Reserves** | **80,893** | **80,746** | **67,527** | **15,143** | **15,138** | **13,283** | **20,761** | **20,726** | **14,941** |
| Probable Reserves | 28,918 | 28,873 | 24,015 | 11,206 | 11,205 | 10,336 | 8,067 | 8,057 | 6,043 |
| **Total Proved Plus Probable Reserves** | **109,811** | **109,620** | **91,542** | **26,349** | **26,343** | **23,619** | **28,827** | **28,783** | **20,983** |

| Reserves Category | Natural Gas | | | Coal Bed Methane | | | Total Oil Equivalent Basis[(3)] | | |
|---|---|---|---|---|---|---|---|---|---|
| | Company Interest (MMcf) | Gross Interest (MMcf) | Net Interest (MMcf) | Company Interest (MMcf) | Gross Interest (MMcf) | Net Interest (MMcf) | Company Interest (Mboe) | Gross Interest (Mboe) | Net Interest (Mboe) |
| **Proved Reserves** | | | | | | | | | |
| Proved Developed Producing | 462,175 | 459,940 | 399,088 | 23,102 | 22,810 | 21,419 | 176,972 | 176,374 | 149,084 |
| Proved Developed Non-Producing | 20,922 | 20,832 | 17,268 | 1,905 | 1,894 | 1,608 | 6,821 | 6,803 | 5,485 |
| Proved Undeveloped | 50,602 | 50,602 | 44,926 | 23,626 | 23,559 | 20,242 | 30,058 | 30,040 | 25,274 |
| **Total Proved Reserves** | **533,699** | **531,374** | **461,281** | **48,633** | **48,262** | **43,269** | **213,852** | **213,216** | **179,843** |
| Probable Reserves | 268,528 | 267,871 | 233,465 | 11,740 | 11,648 | 10,575 | 94,903 | 94,722 | 81,067 |
| **Total Proved Plus Probable Reserves** | **802,227** | **799,245** | **694,746** | **60,373** | **59,911** | **53,844** | **308,754** | **307,938** | **260,910** |

### Notes:

(1) Constant prices are shown under the heading *"Pricing Assumptions"*.

(2) Includes 6,348 Mbbl of Company Interest heavy oil Probable Reserves for the Lindbergh oil sands property in the GLJ Report.

(3) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

## Summary of Net Present Value of Future Net Revenue as of December 31, 2010 Before and After Income Tax (Constant Prices and Costs)(1)

| Reserves Category | Before Income Taxes Discounted At (%/Year) 0% ($MM) | 5% ($MM) | 10% ($MM) | 15% ($MM) | 20% ($MM) | Unit Value Before Income Taxes Discounted at 10%/Year(2)(3) $/boe | $/Mcfe |
|---|---|---|---|---|---|---|---|
| **Proved Reserves** | | | | | | | |
| Proved Developed Producing | 3,733 | 2,893 | 2,382 | 2,039 | 1,793 | 15.98 | 2.66 |
| Proved Developed Non-Producing | 114 | 74 | 52 | 39 | 31 | 9.55 | 1.59 |
| Proved Undeveloped | 612 | 331 | 183 | 99 | 47 | 7.25 | 1.21 |
| **Total Proved Reserves** | **4,459** | **3,297** | **2,618** | **2,177** | **1,871** | **14.56** | **2.43** |
| Probable Reserves | 1,971 | 1,089 | 687 | 469 | 337 | 8.47 | 1.41 |
| **Total Proved Plus Probable Reserves** | **6,431** | **4,386** | **3,304** | **2,646** | **2,208** | **12.66** | **2.11** |

| Reserves Category | After Income Taxes Discounted At (%/Year)(4) 0% ($MM) | 5% ($MM) | 10% ($MM) | 15% ($MM) | 20% ($MM) |
|---|---|---|---|---|---|
| **Proved Reserves** | | | | | |
| Proved Developed Producing | 3,638 | 2,895 | 2,374 | 1,996 | 1,713 |
| Proved Developed Non-Producing | 89 | 59 | 41 | 29 | 21 |
| Proved Undeveloped | 471 | 259 | 134 | 60 | 15 |
| **Total Proved Reserves** | **4,198** | **3,213** | **2,549** | **2,085** | **1,749** |
| Probable Reserves | 1,459 | 834 | 503 | 320 | 214 |
| **Total Proved Plus Probable Reserves** | **5,657** | **4,047** | **3,052** | **2,405** | **1,963** |

**Notes:**

(1) Constant prices are shown under the heading *"Pricing Assumptions"*.

(2) Net present value of future net revenue per reserve unit values are based on our net reserves.

(3) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil. Oil has been converted to thousand cubic feet of natural gas equivalent on the basis of one barrel of oil being equal to six Mcf of natural gas.

(4) After tax values were calculated using current corporate tax rates, existing tax pools and additions to the tax pools through capital expenditures as forecast by GLJ. See – "*Statement of Oil and Gas Reserves and Reserves Data – Disclosure of Reserves Data*" for additional descriptions of the assumptions made in calculating the after tax values.

## Additional Information Concerning Future Net Revenue (undiscounted) as of December 31, 2010 (Constant Prices and Costs)[1]

| Reserves Category | Revenue ($MM) | Royalties[2] ($MM) | Operating Costs ($MM) | Development Costs ($MM) | Abandonment Costs[3] ($MM) | Future Net Revenue Before Income Taxes ($MM) | Income Tax ($MM) | Future net Revenue After Income Taxes ($MM) |
|---|---|---|---|---|---|---|---|---|
| Proved Reserves | 10,759 | 1,778 | 3,778 | 553 | 191 | 4,459 | 261 | 4,198 |
| Total Proved Plus Probable Reserves | 15,197 | 2,469 | 5,111 | 988 | 198 | 6,431 | 774 | 5,657 |

**Notes:**

(1) Constant prices are shown under the heading *"Pricing Assumptions"*.

(2) Crown royalties payable to the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia and any freehold and over-riding royalties payable. This includes the impact of the New Royalty Framework implemented by the Government of Alberta on January 1, 2009, the optional Transitional Royalty and any drilling incentive programs still in effect.

(3) Includes GLJ's estimate of well abandonment costs and abandonment of Sable Island facilities and subsea pipelines, but does not include abandonment costs for other facilities or any surface reclamation costs. See "*Pengrowth – Operational Information – Additional Information Concerning Abandonment & Reclamation Costs*".

## Net Present Value of Future Net Revenue By Production Group as of December 31, 2010 (Constant Prices and Costs)[1]

| Reserves Category | Production Group | Future Net Revenue Before Income Taxes (discounted at 10%/yr) ($MM) | Unit Value[4][5] ($/boe) | Unit Value[4][5] ($/Mcfe) |
|---|---|---|---|---|
| Total Proved Reserves | Light and Medium Crude Oil (including solution gas and other by-products)[2] | 1,581 | 19.29 | 3.22 |
| | Heavy Crude Oil (including solution gas and other by-products)[2] | 321 | 21.66 | 3.61 |
| | Natural Gas (including by-products but excluding solution gas from oil wells)[3] | 689 | 9.08 | 1.51 |
| | Non-conventional Oil & Gas Activities | 27 | 3.69 | 0.62 |
| | **Total** | **2,618** | **14.56** | **2.43** |
| Total Proved Plus Probable Reserves | Light and Medium Crude Oil (including solution gas and other by-products)[2] | 1,963 | 17.72 | 2.95 |
| | Heavy Crude Oil (including solution gas and other by-products)[2] | 397 | 15.46 | 2.58 |
| | Natural Gas (including by-products but excluding solution gas from oil wells)[3] | 909 | 7.87 | 1.31 |
| | Non-conventional Oil & Gas Activities | 36 | 4.00 | 0.67 |
| | **Total** | **3,304** | **12.66** | **2.11** |

**Notes:**

(1) Constant prices are shown under the heading *"Pricing Assumptions"*.

(2) NGL associated with the production of solution gas are included as a by-product.

(3) NGL associated with the production of natural gas are included as a by-product.

(4) Net present value of future net revenue per boe or Mcfe are based on our net reserves.

(5) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil. Oil has been converted to thousand cubic feet of natural gas equivalent on the basis of one barrel of oil being equal to six Mcf of natural gas.

*Pricing Assumptions*

*Forecast Prices used in Estimates*

The forecast price and cost assumptions assume the continuance of current laws and regulations and changes in wellhead selling prices, and take into account forecasted two percent annual inflation with respect to future operating and capital costs. The forecast prices are provided in the table below and reflect GLJ's January 1, 2011 price forecast as referred to in the GLJ Report.

| | **Oil** | | | | **Natural Gas** | **Natural Gas Liquids**[(1)] | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **WTI Cushing Oklahoma** (US$/bbl) | **Edmonton Par Price 40°API** (Cdn$/bbl) | **Cromer Medium 29.3°API** (Cdn$/bbl) | **Hardisty Heavy 12° API** (Cdn$/bbl) | **AECO Gas Price** (Cdn$/MMBtu) | **Propane** (Cdn$/bbl) | **Butane** (Cdn$/bbl) | **Pentanes Plus** (Cdn$/bbl) | **Inflation Rates**[(2)] (%/Year) | **Exchange Rate**[(3)] (US$/Cdn$) |
| 2010[(4)] | 79.42 | 78.02 | 73.81 | 60.62 | 4.17 | 46.87 | 65.59 | 84.04 | - | - |
| 2011 | 88.00 | 86.22 | 82.78 | 68.79 | 4.16 | 54.32 | 67.26 | 90.54 | 2.0 | 0.98 |
| 2012 | 89.00 | 89.29 | 83.04 | 68.33 | 4.74 | 56.25 | 68.75 | 91.96 | 2.0 | 0.98 |
| 2013 | 90.00 | 90.92 | 83.64 | 67.03 | 5.31 | 57.28 | 70.01 | 92.74 | 2.0 | 0.98 |
| 2014 | 92.00 | 92.96 | 84.59 | 67.84 | 5.77 | 58.56 | 71.58 | 94.82 | 2.0 | 0.98 |
| 2015 | 95.17 | 96.19 | 87.54 | 70.23 | 6.22 | 60.60 | 74.07 | 98.12 | 2.0 | 0.98 |
| 2016 | 97.55 | 98.62 | 89.75 | 72.03 | 6.53 | 62.13 | 75.94 | 100.59 | 2.0 | 0.98 |
| 2017 | 100.26 | 101.39 | 92.26 | 74.08 | 6.76 | 63.87 | 78.07 | 103.42 | 2.0 | 0.98 |
| 2018 | 102.74 | 103.92 | 94.57 | 75.95 | 6.90 | 65.47 | 80.02 | 106.00 | 2.0 | 0.98 |
| 2019 | 105.45 | 106.68 | 97.08 | 78.00 | 7.06 | 67.21 | 82.15 | 108.82 | 2.0 | 0.98 |
| 2020 | 107.56 | 108.84 | 99.04 | 79.59 | 7.21 | 68.57 | 83.80 | 111.01 | 2.0 | 0.98 |
| Thereafter | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | +2%/yr | 2.0 | 0.98 |

**Notes:**

(1) FOB Edmonton.

(2) Inflation rates for forecasting prices and costs.

(3) The exchange rates used to generate the benchmark reference prices in this table.

(4) Actual weighted average historical prices for 2010.

*Constant Prices used in Estimates*

The constant price assumptions assume the continuance of current laws, regulations and operating costs in effect on the date of the GLJ Report. Product prices were determined from the actual prices on the first day of each month during 2010 and were not escalated. In addition to the product prices, operating and capital costs have no inflationary increase. The constant prices are as follows:

| | Oil | | | | Natural Gas | Natural Gas Liquids[(1)] | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Year** | **WTI Cushing Oklahoma** (US$/bbl) | **Edmonton Par Price 40° API** (Cdn$/bbl) | **Cromer Medium 29.3° API** (Cdn$/bbl) | **Hardisty Heavy 12° API** (Cdn$/bbl) | **AECO Gas Price** (Cdn$/MMBtu) | **Propane** (Cdn$/bbl) | **Butane** (Cdn$/bbl) | **Pentanes Plus** (Cdn$/bbl) | **Inflation Rate** (%/Year) | **Exchange Rate**[(2)] (US$/Cdn$) |
| 2011 and thereafter | 79.40 | 78.23 | 74.21 | 61.72 | 4.06 | 45.10 | 66.10 | 84.57 | 0.0% | 0.9672 |

**Notes:**

(1) FOB Edmonton.

(2) The exchange rate used to generate the benchmark reference prices in this table.

*Reserves Reconciliation*

The following tables provide a reconciliation of our gross reserves of crude oil, natural gas and NGL for the year ended December 31, 2010, presented using forecast prices and costs. All reserves are located in Canada.

**Reserves Reconciliation**
**By Principal Product Type**
**(Forecast Prices and Costs)**

| | Light and Medium Oil | | | Heavy Oil | | | Natural Gas Liquids | | |
|---|---|---|---|---|---|---|---|---|---|
| | Gross Proved (Mbbl) | Gross Probable (Mbbl) | Gross Proved Plus Probable (Mbbl) | Gross Proved (Mbbl) | Gross Probable (Mbbl) | Gross Proved Plus Probable (Mbbl) | Gross Proved (Mbbl) | Gross Probable (Mbbl) | Gross Proved Plus Probable (Mbbl) |
| **December 31, 2009** | 82,659 | 29,400 | 112,059 | 16,347 | 11,367 | 27,713 | 21,384 | 8,091 | 29,475 |
| Technical Revisions | 2,582 | (459) | 2,124 | 918 | (199) | 719 | 912 | (509) | 403 |
| Discoveries | 88 | 29 | 117 | - | 18 | 18 | 21 | 7 | 28 |
| Extensions | 1,957 | 444 | 2,401 | 53 | 26 | 79 | 1,794 | 241 | 2,035 |
| Infill Drilling | 727 | 133 | 860 | 30 | 32 | 62 | 64 | 11 | 75 |
| Improved Recovery | 779 | (555) | 225 | 363 | (10) | 353 | 17 | 2 | 19 |
| Acquisitions | 274 | 60 | 334 | - | - | - | 505 | 374 | 878 |
| Dispositions | (83) | (29) | (112) | - | - | - | (3) | (1) | (4) |
| Economic Factors | - | - | - | - | - | - | - | - | - |
| Production | (7,907) | - | (7,907) | (2,478) | - | (2,478) | (3,476) | - | (3,476) |
| **December 31, 2010** | 81,077 | 29,024 | 110,101 | 15,232 | 11,233 | 26,465 | 21,216 | 8,216 | 29,432 |

| | Natural Gas | | | Coal Bed Methane | | | Total Oil Equivalent Basis(1) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Gross Proved (MMcf) | Gross Probable (MMcf) | Gross Proved Plus Probable (MMcf) | Gross Proved (MMcf) | Gross Probable (MMcf) | Gross Proved Plus Probable (MMcf) | Gross Proved (Mboe) | Gross Probable (Mboe) | Gross Proved Plus Probable (Mboe) |
| **December 31, 2009** | 529,897 | 169,278 | 699,175 | 41,090 | 11,037 | 52,127 | 215,554 | 78,911 | 294,465 |
| Technical Revisions | 21,671 | (16,808) | 4,864 | 2,841 | (1,432) | 1,408 | 8,497 | (4,208) | 4,289 |
| Discoveries | 231 | 77 | 308 | - | - | - | 148 | 66 | 214 |
| Extensions | 20,668 | 54,462 | 75,130 | 2,105 | 1,256 | 3,361 | 7,599 | 9,997 | 17,596 |
| Infill Drilling | 2,013 | 5,047 | 7,060 | 10,752 | 2,036 | 12,787 | 2,949 | 1,356 | 4,305 |
| Improved Recovery | 366 | 42 | 408 | - | - | - | 1,219 | (556) | 664 |
| Acquisitions | 64,401 | 67,448 | 131,849 | - | - | - | 11,512 | 11,675 | 23,187 |
| Dispositions | (222) | (58) | (280) | (56) | (29) | (85) | (132) | (45) | (177) |
| Economic Factors | - | - | - | - | - | - | - | - | - |
| Production | (74,962) | - | (74,962) | (4,051) | - | (4,051) | (27,029) | - | (27,029) |
| **December 31, 2010** | 564,062 | 279,489 | 843,551 | 52,680 | 12,866 | 65,547 | 220,316 | 97,198 | 317,514 |

**Note:**

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

At December 31 2010, Company Interest Total Proved Plus Probable Reserves at forecast prices and costs were 318.4 MMboe as compared to 295.7 MMboe reported at year end 2009. The following additional GLJ reserves reconciliation is presented for year end December 31, 2010.

**Company Interest Reserves Reconciliation on Total Oil Equivalent Basis (Forecast Prices and Costs)**

| | Proved Developed Producing Reserves (Mboe)[1] | Proved Reserves (Mboe)[1] | Proved Plus Probable Reserve (Mboe)[1] |
|---|---|---|---|
| **December 31, 2009** | 183,834 | 216,554 | 295,734 |
| Technical Revisions | 11,121 | 8,574 | 4,328 |
| Discoveries | - | 148 | 214 |
| Extensions | 9,197 | 7,607 | 17,606 |
| Infill Drilling | 1,467 | 2,957 | 4,315 |
| Improved Recovery | 2,438 | 1,221 | 664 |
| Acquisitions | 3,115 | 11,534 | 23,214 |
| Dispositions | (244) | (302) | (383) |
| Economic Factors | - | - | - |
| Production | (27,264) | (27,264) | (27,264) |
| **December 31, 2010** | 183,664 | 221,028 | 318,429 |

**Note:**

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

Significant factors bearing on the reserves reconciliation were as follows:

- Reserve additions from drilling activity, improved recovery and technical revisions replaced 75 percent and 99 percent of 2010 production for Total Proved and Total Proved Plus Probable Reserves, respectively. Based on all changes, including acquisitions and dispositions, reserve replacement was 116 percent and 183 percent for Total Proved and Proved Plus Probable Reserves, respectively.

- New reserve additions for development activity during 2010 amounted to 22.8 MMboe of Total Proved Plus Probable Reserves. Most significant were drilling extensions in our resource plays at Groundbirch, Carson Creek and Harmattan. Reserve increases in the Proved Developed Producing category also resulted from the reclassification of Proved or Probable Undeveloped Reserves to producing primarily for drilling extensions at Carson Creek, Harmattan and Deer Mountain.

- Acquisitions net of some minor dispositions, resulted in an increase of 22.8 MMboe to Proved Plus Probable Reserves. This was almost entirely from the acquisition of Monterey Exploration Ltd. with the large majority of the reserves associated with the Groundbirch Montney resource play.

## Additional Information Relating to Reserves Data

*Undeveloped Reserves*

Undeveloped Reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Proved and Probable Undeveloped Reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. In general, Undeveloped Reserves are scheduled to be developed within the next two to three years. Much of the remaining capital scheduled beyond this period is related to the Weyburn, Judy Creek and Swan Hills EOR projects, which have staged development plans, and the Groundbirch gas and Lindbergh oil sands projects which will be drilled up over time to keep the respective facilities full.

## Company Gross Reserves
## First Attributed by Year[(1)]

**Proved Undeveloped Reserves**

| | Light & Medium Oil (Mbbl) | | Heavy Oil (Mbbl) | | Natural Gas (MMcf) | | Coal Bed Methane (MMcf) | | Natural Gas Liquids (Mbbl) | | Total Oil Equivalent (Mboe)[(2)] | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | First Attributed | Total at year-end | First Attributed | Total at year-end | First Attributed | Total at year-end | First Attributed | Total at year-end | First Attributed | Total at year-end | First Attributed | Total at year-end |
| Prior | 18,985 | 18,985 | 2,194 | 2,194 | 50,224 | 50,224 | 13,911 | 13,911 | 1,361 | 1,361 | 33,229 | 33,229 |
| 2008 | 1,000 | 17,029 | 382 | 1,676 | 3,513 | 48,311 | 1,858 | 10,372 | 125 | 1,120 | 2,402 | 29,606 |
| 2009 | 1,347 | 16,351 | 130 | 1,846 | 2,778 | 30,359 | 10,140 | 19,184 | 209 | 1,190 | 3,840 | 27,644 |
| 2010 | 1,386 | 15,077 | 30 | 1,732 | 30,017 | 51,742 | 10,435 | 24,955 | 516 | 878 | 8,674 | 30,470 |

**Probable Undeveloped Reserves**

| | Light & Medium Oil (Mbbl) | | Heavy Oil (Mbbl) | | Natural Gas (MMcf) | | Coal Bed Methane (MMcf) | | Natural Gas Liquids (Mbbl) | | Total Oil Equivalent (Mboe)[(2)] | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | First Attributed | Total at year-end | First Attributed | Total at year-end | First Attributed | Total at year-end | First Attributed | Total at year-end | First Attributed | Total at year-end | First Attributed | Total at year-end |
| Prior | 13,497 | 13,497 | 2,269 | 2,269 | 64,986 | 64,986 | 10,155 | 10,155 | 2,716 | 2,716 | 31,006 | 31,006 |
| 2008 | 1,850 | 12,372 | 6,997 | 7,857 | 17,686 | 68,222 | 4,514 | 7,948 | 782 | 3,478 | 13,329 | 36,502 |
| 2009 | 1,565 | 11,514 | 68 | 7,853 | 9,450 | 37,134 | 2,177 | 5,178 | 934 | 2,510 | 4,505 | 28,929 |
| 2010 | 708 | 10,168 | 50 | 7,613 | 99,381 | 145,695 | 2,809 | 6,318 | 1,284 | 2,879 | 19,073 | 45,996 |

**Notes:**

(1) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year.

(2) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

*Proved Undeveloped Reserves*

Our Proved Undeveloped Reserves comprise approximately 14 percent of the Company Interest Total Proved Reserves on a barrel of oil equivalency basis. Company Interest Proved Undeveloped Reserves of 30.5 MMboe were assigned by GLJ in accordance with NI 51-101. In general, Proved Undeveloped Reserves were assigned to certain properties because we intend to make the needed capital commitments to convert the Undeveloped Reserves to Proved Developed Producing Reserves in the next few years. Proved Undeveloped Reserves have been primarily assigned for future miscible flood expansion and development drilling.

The Groundbirch property, acquired in 2010, accounts for approximately 18 percent of our Proved Undeveloped Reserves. Drilling is forecast by GLJ to occur over the next five years to develop these reserves. Swan Hills miscible flood expansion, as well as some infill drilling, comprises 14 percent of our Company Interest Proved Undeveloped Reserves. The Swan Hills unit reserves have a 50 year Remaining Reserve Life. The incremental recovery is reflected in the GLJ Report and miscible flood expansion is forecasted to continue until 2027. Similarly at Judy Creek, miscible flood development is forecast to continue until 2014 and accounts for another 14 percent of the Company Interest Proved Undeveloped Reserves. In the Weyburn Unit, the Proved Undeveloped Reserves also amounts to 14 percent of the total, reflects the capital allocated to infill drilling and the CO2 miscible flood. Working interest partners have committed to a CO2 supply until 2016. Further development of the flood area in the Weyburn Unit, from the existing 58 patterns to full development with 76 patterns in the proved case, is forecast to occur by 2014. Development of all 92 patterns in the probable case continues until 2016. Given that CO2 injection is still in the early planning and pilot stages, no full scale CO2 miscible flood is being forecast at Judy Creek.

Our ongoing CBM development requires further infill drilling and drilling extensions at Twining, Huxley and Fenn Big Valley. Because of the extensive land holdings, this is forecast to occur over the next five years and represents approximately 13 percent of the Proved Undeveloped Reserves. Multi-well shallow gas infill drilling programs are scheduled for 2011 and beyond at Monogram, Patricia and Dinosaur, which together contain four percent of the Company Interest Total Proved Undeveloped Reserves. Ongoing development is scheduled in heavy oil properties where approximately four percent of Pengrowth's Company Interest Proved Undeveloped Reserves are assigned to the waterflood expansion in East Bodo that is forecast to occur in 2011. At Deer Mountain, waterflood optimization, drilling extensions and infill drilling scheduled over the next two years account for about three percent of the Company Interest Proved Undeveloped Reserves.

*Probable Undeveloped Reserves*

Probable Undeveloped Reserves were assigned by GLJ in accordance with the requirements and standards of NI 51-101 and the COGE Handbook. Our Probable Undeveloped Reserves amount to 46.0 MMboe and represent about 14 percent of the Total Proved Plus Probable Reserves. Probable Undeveloped Reserves are assigned for similar reasons and generally to the same properties as Proved Undeveloped Reserves, but also meet the requirements of the reserve classification to which they belong. Our largest Probable Undeveloped Reserves are distributed among certain properties as a percent of the total as follows: Groundbirch (38 percent), Lindbergh (14 percent), Weyburn Unit (eight percent), Swan Hills Unit (five percent), Judy Creek (four percent), Carson Creek (three percent), and shallow gas (three percent). Probable Undeveloped Reserves are assigned at Groundbirch for the Montney gas play. Production commenced in December 2010 and drilling extensions are forecast to occur over the next five years to keep the facility running at full capacity. At Lindbergh, Probable Undeveloped Reserves are assigned to a proposed oil sands SAGD pilot project. Facility design and procurement, delineation drilling and other development work is underway with initial production planned for 2012.

## Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue calculated utilizing both constant and forecast prices and costs, undiscounted and using a discount rate of ten percent per annum for the years indicated. All of such development costs are estimated to be incurred in Canada.

| | | | | | | | Total | |
|---|---|---|---|---|---|---|---|---|
| **Reserve Category** | **2011** ($MM) | **2012** ($MM) | **2013** ($MM) | **2014** ($MM) | **2015** ($MM) | **Remainder** ($MM) | **Undiscounted** ($MM) | **Discounted at 10%** ($MM) |
| Proved Reserves (Constant Prices and Costs) | 164 | 124 | 57 | 42 | 26 | 139 | 553 | 406 |
| Proved Reserves (Forecast Prices and Costs) | 164 | 126 | 59 | 45 | 28 | 180 | 603 | 424 |
| Proved & Probable Reserves (Forecast Prices and Costs) | 281 | 225 | 146 | 82 | 42 | 303 | 1,079 | 760 |

We expect to fund future development costs with a combination of cash flow, debt and equity. There are no reserves that are expected to be limited in their recovery due to their cost of development. We have established a $400 million capital expenditure program for 2011 to fund our land acquisition, development and exploration activities, including expenditures at our proposed Lindbergh oil sands SAGD pilot project.

## Finding, Development and Acquisition Costs

*Finding and Development Costs*

During 2010, we spent $329.5 million, net of Alberta drilling royalty credits, on development and optimization activities, which added 20.5 MMboe of Proved Reserves and 27.1 MMboe of Total Proved Plus Probable Reserves including revisions. The development and optimization activities exclude $4.4 million in expenditures mainly for information technology projects in the Calgary office. The largest reserve additions were for drilling extensions at Groundbirch, Carson Creek and Harmattan.

In total, we participated in drilling 214 gross wells (128 net wells) with a 96 percent success rate.

Extensive development occurred in the Carson Creek Beaverhill Lake Unit during 2010. Following a nine well horizontal program in 2009, another seven horizontal wells that were multi-stage fractured were drilled in 2010 in this liquids-rich gas reservoir. A successful well was also drilled off the main pool just outside the unit which will lead to further delineation and development drilling in 2011.

In the Harmattan area, we drilled 12 successful horizontal wells resulting in five Cardium oil wells, three Viking oil wells and four Elkton gas wells.

In the Deer Mountain area, we drilled six unit and four non-unit horizontal wells in the Beaverhill Lake oil pool. Eight wells were multi-stage fractured and began producing in 2010. Two unit wells were being completed in early 2011. In addition, we continue to optimize injection patterns and waterflood performance in the unit.

Following the acquisition of Monterey in September 2010, we drilled four Montney horizontal gas wells at Groundbirch and completed three wells that were multi-stage fractured. In addition, gas plant construction and tie-ins were completed with five wells beginning production before year-end.

At Judy Creek, ongoing development drilling and optimization of the waterflood and hydrocarbon miscible flood projects continue to be a focus for us. Similar miscible flood development as well as infill drilling occurred in the Swan Hills Unit No. 1.

Further development and optimization occurred in the CO2 miscible flood and waterflood areas of the Weyburn Unit in southeast Saskatchewan. During 2010, 32 wells were drilled in the unit, consisting of 28 water and CO2 injection wells, two producers and two observation wells.

Various other drilling programs and optimization work were conducted during 2010 to test new concepts, increase production and maximize recoveries. In the Princess and Jenner areas 52 infill shallow gas wells were drilled. Ongoing development in the East Bodo waterflood occurred with seven new vertical producers and three injectors drilled in 2010. Proof of concept horizontal drilling and recompletion operations were initiated in 2010 in an effort to increase recovery in the Pekisko formation at Twining. In the partner operated Dunvegan Gas Unit, eight successful vertical Middle Debolt wells and 1 horizontal Upper Debolt well were drilled.

*Acquisitions and Divestitures*

We made one large acquisition during 2010 that created a new core area. The acquisition of Monterey represented a significant step forward in our value creation strategy by providing multiple operated, low risk drilling opportunities in the early stages of a Montney resource play development in the Groundbirch area of Northeast British Columbia. In 2010, we had spent an aggregate of $461.3 million to acquire 11.5 MMboe of Proved Reserves and 23.2 MMboe of Total Proved Plus Probable Reserves (reserve values effective as of the acquisition dates). Minor asset acquisitions were made at Judy Creek and Swalwell to increase interests in existing core areas. In addition, we consolidated our ownership in Twining/Fenn Big Valley CBM lands through a series of land swaps.

In early 2010, we sold gross overriding royalties on a number of our non-core properties. The proceeds from this sale totaled $38.4 million. Total proceeds from minor dispositions of small, isolated properties and undeveloped acreage during 2010 were $22.3 million, resulting in a decrease of 0.3 MMboe Proved Reserves and 0.4 MMboe Total Proved Plus Probable Reserves.

## Future Development Capital

NI 51-101 requires that the calculation of finding and development costs include changes in forecasted future development capital (“**FDC**”) relating to the reserves. FDC reflects the amount of capital estimated by the independent evaluator that will be required to bring non-producing, undeveloped or probable reserves on stream. These forecasts of FDC will change with time due to ongoing development activity, inflationary changes in capital costs and acquisition or disposition of assets. We provide the calculation of finding, development and acquisition costs both with and without change in FDC.

**Finding, Development and Acquisition Costs**
**Company Interest Reserves**
**(Forecast Prices and Costs)**

| | 2010 Proved | 2009 Proved | 2008 Proved | 2008-2010 Weighted Average Proved |
|---|---|---|---|---|
| **Costs Excluding Future Development Capital** | | | | |
| Exploration and Development Capital Expenditures - $M | 329,470 | 202,200 | 388,300 | 919,970 |
| Exploration and Development Reserve Additions including Revisions - Mboe | 20,505 | 11,291 | 17,677 | 49,473 |
| Finding and Development Cost - $/boe | 16.07 | 17.91 | 21.97 | 18.60 |
| Net Acquisition Capital - $M | 400,600 | (6,230) | 130,795 | 525,165 |
| Net Acquisition Reserve Additions - Mboe | 11,232 | (937) | 6,437 | 16,732 |
| Net Acquisition Cost - $/boe | 35.67 | 6.65 | 20.32 | 31.39 |
| Total Capital Expenditures including Net Acquisitions - $M | 730,070 | 195,970 | 519,095 | 1,445,135 |
| Reserve Additions including Net Acquisitions - Mboe | 31,737 | 10,354 | 24,114 | 66,205 |
| Finding Development and Acquisition Cost - $/boe | 23.00 | 18.93 | 21.53 | 21.83 |
| **Costs Including Future Development Capital** | | | | |
| Exploration and Development Capital Expenditures - $M | 329,470 | 202,200 | 388,300 | 919,970 |
| Exploration and Development Change in FDC - $M | 32,000 | (42,800) | 12,000 | 1,200 |
| Exploration and Development Capital including Change in FDC - $M | 361,470 | 159,400 | 400,300 | 921,170 |
| Exploration and Development Reserve Additions including Revisions - Mboe | 20,505 | 11,291 | 17,677 | 49,473 |
| Finding and Development Cost - $/boe | 17.63 | 14.12 | 22.65 | 18.62 |
| Net Acquisition Capital - $M | 400,600 | (6,230) | 130,795 | 525,165 |
| Net Acquisition FDC - $M | 34,000 | 800 | 1,000 | 35,800 |
| Net Acquisition Capital including FDC - $M | 434,600 | (5,430) | 131,795 | 560,965 |
| Net Acquisition Reserve Additions - Mboe | 11,232 | (937) | 6,437 | 16,732 |
| Net Acquisition Cost - $/boe | 38.69 | 5.80 | 20.47 | 33.53 |
| Total Capital Expenditures including Net Acquisitions - $M | 730,070 | 195,970 | 519,095 | 1,445,135 |
| Total Change in FDC - $M | 66,000 | (42,000) | 13,000 | 37,000 |
| Total Capital including Change in FDC - $M | 796,070 | 153,970 | 532,095 | 1,482,135 |
| Reserve Additions including Net Acquisitions - Mboe | 31,737 | 10,354 | 24,114 | 66,205 |
| Finding Development and Acquisition Cost including FDC - $/boe | 25.08 | 14.87 | 22.07 | 22.39 |

| | 2010 Proved plus Probable | 2009 Proved plus Probable | 2008 Proved plus Probable | 2008-2010 Weighted Average Proved plus Probable |
|---|---|---|---|---|
| **Costs Excluding Future Development Capital** | | | | |
| Exploration and Development Capital Expenditures - $M | 329,470 | 202,200 | 388,300 | 919,970 |
| Exploration and Development Reserve Additions including Revisions - Mboe | 27,127 | 2,577 | 23,863 | 53,567 |
| Finding and Development Cost - $/boe | 12.15 | 78.46 | 16.27 | 17.17 |
| Net Acquisition Capital - $M | 400,600 | (6,230) | 130,795 | 525,165 |
| Net Acquisition Reserve Additions - Mboe | 22,832 | (1,283) | 9,688 | 31,237 |
| Net Acquisition Cost - $/boe | 17.55 | 4.86 | 13.50 | 16.81 |
| Total Capital Expenditures including Net Acquisitions - $M | 730,070 | 195,970 | 519,095 | 1,445,135 |
| Reserve Additions including Net Acquisitions - Mboe | 49,959 | 1,294 | 33,551 | 84,804 |
| Finding Development and Acquisition Cost - $/boe | 14.61 | 151.45 | 15.47 | 17.04 |
| **Costs Including Future Development Capital** | | | | |
| Exploration and Development Capital Expenditures - $M | 329,470 | 202,200 | 388,300 | 919,970 |
| Exploration and Development Change in FDC - $M | 86,000 | (122,800) | 180,000 | 143,200 |
| Exploration and Development Capital including Change in FDC - $M | 415,470 | 79,400 | 568,300 | 1,063,170 |
| Exploration and Development Reserve Additions including Revisions - Mboe | 27,127 | 2,577 | 23,863 | 53,567 |
| Finding and Development Cost - $/boe | 15.32 | 30.81 | 23.82 | 19.85 |
| Net Acquisition Capital - $M | 400,600 | (6,230) | 130,795 | 525,165 |
| Net Acquisition FDC - $M | 106,000 | 800 | 10,000 | 116,800 |
| Net Acquisition Capital including FDC - $M | 506,600 | (5,430) | 140,795 | 641,965 |
| Net Acquisition Reserve Additions - Mboe | 22,832 | (1,283) | 9,688 | 31,237 |
| Net Acquisition Cost - $/boe | 22.19 | 4.23 | 14.53 | 20.55 |
| Total Capital Expenditures including Net Acquisitions - $M | 730,070 | 195,970 | 519,095 | 1,445,135 |
| Total Change in FDC - $M | 192,000 | (122,000) | 190,000 | 260,000 |
| Total Capital including Change in FDC - $M | 922,070 | 73,970 | 709,095 | 1,705,135 |
| Reserve Additions including Net Acquisitions - Mboe | 49,959 | 1,294 | 33,551 | 84,804 |
| Finding Development and Acquisition Cost including FDC - $/boe | 18.46 | 57.16 | 21.13 | 20.11 |

## Recycle Ratio

We calculate the recycle ratio to measure our performance. It reflects the amount of cash flow relative to investment and is able to be compared both internally and externally. To calculate the recycle ratio, we divide annual operating netback by annual P+P F&D Costs including change in FDC.

| | 2010 | 2009 | 2008 | 2008-2010 Weighted Average |
|---|---|---|---|---|
| Recycle Ratio, $/$ | 1.72 | 0.82 | 1.46 | 1.46 |
| Operating Netback, $/boe(1) | 26.37 | 25.38 | 34.78 | 28.96 |
| P+P F&D, $/boe(2) | 15.32 | 30.81 | 23.82 | 19.85 |

**Notes:**

(1) Operating netback is calculated as shown in "*Production History (Netback)*".

(2) P+P F&D uses Exploration and Development capital including Change in FDC divided by Exploration and Development Reserve Additions including Revisions as shown above.

## Reserve Life Index (RLI)

The reserve life index provides a comparative measure of the longevity of the resources. We calculate the RLI by dividing 2010 Company Interest year-end reserves by GLJ's 2011 forecasted production.

| | PDP | TP | P+P |
|---|---|---|---|
| RLI, years | 7.2 | 8.2 | 11.1 |
| Reserves, Mboe(1)(2) | 183,664 | 221,028 | 318,429 |
| 2011 Forecast Production, Boe/d(1) | 70,204 | 74,061 | 78,820 |

**Notes:**

(1) Both reserves and production are Company Interest.

(2) Reserves are calculated using Forecast Prices and Costs.

## Reserve Replacement

We provide reserve replacement data as an indication of the effectiveness of our investments made and the relative impact of that investment. The reserve replacement figures are calculated with and without net acquisitions included.

| | 2010 | 2009 | 2008 | Weighted Average 2008-2010 |
|---|---|---|---|---|
| Without Net Acquisitions Proven Plus Probable Replacement % | 99% | 9% | 80% | 62% |
| P+P Drill Adds plus Revisions, MMboe(1) | 27.1 | 2.6 | 23.9 | 53.6 |
| With Net Acquisitions Proven Plus Probable Replacement % | 183% | 4% | 112% | 98% |
| P+P Adds, Revisions plus net Acquisitions, MMboe(1) | 50.0 | 1.3 | 33.6 | 84.8 |
| Without Net Acquisitions Total Proved Replacement % | 75% | 39% | 59% | 57% |
| Total Proved Drill Adds plus Revisions, MMBoe(1) | 20.5 | 11.3 | 17.7 | 49.2 |
| With Net Acquisitions Total Proved Replacement, % | 116% | 36% | 80% | 77% |
| Total Proved Adds, Revisions plus net Acquisitions, MMboe(1) | 31.7 | 10.4 | 24.1 | 66.2 |
| Current Year Production, MMboe(1) | 27.3 | 29.0 | 30.0 | 86.3 |

**Note:**

(1) Both reserves and production are Company Interest. Note that natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

## Other Oil and Gas Information

*Oil and Gas Wells*

As at December 31, 2010, we had an interest in 8,277 gross (4,138 net) producing oil and natural gas wells and 2,463 gross (1,366 net) non-producing oil and natural gas wells.

| | Producing | | Non-Producing | |
|---|---|---|---|---|
| | Gross | Net | Gross | Net |
| **Crude Oil Wells** | | | | |
| Alberta | 1,757 | 1,124 | 797 | 472 |
| British Columbia | 91 | 58 | 157 | 100 |
| Saskatchewan | 909 | 192 | 462 | 178 |
| Nova Scotia | - | - | - | - |
| **Natural Gas Wells** | | | | |
| Alberta | 5,181 | 2,569 | 514 | 271 |
| British Columbia | 278 | 162 | 125 | 73 |
| Saskatchewan | 42 | 31 | 39 | 24 |
| Nova Scotia | 19 | 2 | - | - |
| **Other(1)** | | | | |
| Alberta | - | - | 247 | 163 |
| British Columbia | - | - | 70 | 54 |
| Saskatchewan | - | - | 52 | 31 |
| **Total** | **8,277** | **4,138** | **2,463** | **1,366** |

**Note:**

(1) We cannot classify these wells as either oil or gas.

*Properties with No Attributed Reserves*

The following table sets forth the gross and net acres of unproved properties held by us as at December 31, 2010 and the maximum net area of unproved properties for which we expect our rights to explore, develop and exploit to expire during 2011. There are no material work commitments necessary to maintain these properties.

### Unproved Properties as at December 31, 2010

| Location | Gross Acres | Net Acres | Maximum Net Acres That May Expire During 2011 |
|---|---|---|---|
| Alberta | 861,332 | 606,134 | 90,569 |
| British Columbia | 455,118 | 240,875 | 45,827 |
| Ontario | 4,776 | - | - |
| Saskatchewan | 61,011 | 41,432 | 1,999 |
| Nova Scotia | 200,650 | 15,957 | - |
| **Total** | **1,552,887** | **904,398** | **138,395** |

The expiring acreage is being evaluated and attempts will be made to maintain our rights on the acreage. Historically, efforts to maintain our rights on acreage on activity have been successful.

*Lindbergh Oil Sands Reserves and Contingent Resources*

The Lindbergh oil sands property is located approximately 420 kilometres northeast of Calgary and 65 kilometres southwest of Cold Lake. We hold a 100 percent Working Interest in this oil sands asset where oil quality averages 11°API. The Upper Lloydminster and Lower Rex are the targeted formations. These formations contain bitumen-saturated sands up to 23 metres thick at approximately 500metres depth.

We are planning a pilot that is the basis for the Probable Reserves and Probable plus Possible Reserves currently assigned to this property. In addition, there are Contingent Resources for the area surrounding the pilot. GLJ has updated the evaluation of the reserves and Contingent Resources for Lindbergh as of December 31, 2010. The evaluation was limited to portions of the reservoir amenable to steam assisted gravity drainage (SAGD). The pilot's profitability will be sensitive to oil prices and reservoir quality. The pilot is forecast to be profitable using forecast prices and costs as well as constant prices and costs.

The tables below summarize the estimated volumes of Company Interest reserves and Contingent Resources attributable to the Lindbergh property based upon forecast prices and costs. The estimates are in accordance with the definitions and guidelines in the COGE Handbook and NI 51-101. Please note that reserves and Contingent Resources involve different risks associated with achieving commerciality. Under the fiscal conditions, including commodity price and cost assumptions, applied in the estimation of reserves, the likelihood that a project will achieve commerciality is assumed to be 100 percent, whereas the likelihood of a Contingent Resource achieving commerciality may be less than 100 percent.

Probable Reserves have been assigned within the region of the proposed pilot development area. Probable plus Possible Reserves have been assigned to this same pilot area as well as a previously delineated region offsetting the pilot. There is no change in the estimate of Probable Reserves and minor changes in the net present values due to slightly higher forecasted oil prices and a revised development plan for the pilot. The Probable Reserves attributed to the Lindbergh property have been included in the reserves disclosed under "- *Statement of Oil and Gas Reserves and Reserves Data*". The estimate of Probable Plus Possible Reserves has decreased due to the reporting limitation of a 50 year forecast life at a lower peak production rate now planned for the pilot stage. The high estimate of Contingent Resources summarized below has been increased by the amount the Probable Plus Possible Reserves have been decreased, as the 50 year life does not limit recovery at the current expected peak rate for the commercial phase.

**Lindberg Oil Sands Pilot Project Probable and**
**Probable plus Possible Reserves and Net Present Value of Future Net Revenue**
**as of December 31, 2010**
**(Forecast Prices and Costs)**

| | Probable Reserves[1] | Probable plus Possible Reserves |
|---|---|---|
| Gross Reserves (MMbbl) | 6.3 | 18.5 |
| Before tax net present value of future net revenue | | |
| 0% discount rate ($MM) | 118.7 | 627.6 |
| 5% discount rate ($MM) | 54.8 | 161.2 |
| 10% discount rate ($MM) | 21.3 | 54.1 |
| 15% discount rate ($MM) | 2.2 | 16.5 |
| 20% discount rate ($MM) | (9.4) | (1.5) |

**Note:**

(1) GLJ has estimated our undiscounted pilot capital to be $112 million and the ten percent discounted pilot capital amount to be $75 million to develop the Probable Reserves.

Contingent Resources have been assigned to the remaining areas of the reservoir within the property that meet certain minimum criteria. In order to be classified as a Contingent Resource, a technically feasible recovery project must be defined. These Contingent Resources are expected to be economic to develop. The reclassification of these Contingent Resources as reserves is contingent upon further reservoir studies, delineation drilling, facility design, preparation of firm development plans, regulatory application approval and corporate approvals. However, there is no certainty that it will be commercially viable to produce any portion of the Contingent Resource.

| | December 31, 2009 Contingent Resources[1] (Gross) (MMbbl) | December 31, 2010 Contingent Resources[1] (Gross) (MMbbl) |
|---|---|---|
| Low estimate[2] | 148.5 | 148.5 |
| Best estimate[3] | 193.4 | 193.4 |
| High Estimate[4] | 241.1 | 257.9 |

**Notes:**

(1) Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. The contingencies may include factors such as economics, legal, environmental, political, regulatory or lack of markets. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates.

(2) A low estimate is a conservative estimate of the quantity of oil that will be recovered from the accumulation, which under probabilistic methodology reflects a ninety percent confidence level.

(3) A best estimate is a best estimate of the quantity of oil that will be recovered from the accumulation, which under probabilistic methodology reflects a fifty percent confidence level.

(4) A high estimate is an optimistic estimate of the quantity of oil that will be recovered from the accumulation, which under probabilistic methodology reflects a ten percent confidence level.

The accuracy of resource estimates is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. These resource volumes are classified as a resource rather than a reserve because they are contingent upon further reservoir studies, delineation drilling and facility design, preparation of firm development plans, regulatory application approval and company approvals. The size of the resource estimate could be positively impacted, potentially in a material amount, if additional delineation wells determine that the aerial extent, reservoir quality and/or the thickness of the reservoir is larger than what is currently estimated based on the interpretation of seismic and well control. The size of the resource estimate could be negatively impacted, potentially in a material amount, if additional delineation wells determine that the aerial extent, reservoir quality and/or the thickness of the reservoir are less than what is currently estimated based on the interpretation of the seismic and well control.

*Groundbirch Reserves and Contingent Resources*

The Groundbirch property is located approximately 40 kilometres southwest of Ft. St. John, British Columbia and covers an area of approximately 13,440 acres. We have an average 90 percent Working Interest in the lands that we acquired from Monterey Exploration Ltd. in September 2010.

Production from the Montney formation began on this property in December 2010. For those areas producing and immediately adjacent, GLJ has assigned proven, probable and possible reserves. For areas outside of this, GLJ has completed a Contingent Resource assessment.

The tables below summarize the estimated volumes of Company Interest reserves and Contingent Resources attributable to the Groundbirch property based upon forecast prices and costs. The estimates are in accordance with the definitions and guidelines in the COGE Handbook and NI 51-101. Please note that reserves and Contingent Resources involve different risks associated with achieving commerciality. Under the fiscal conditions, including commodity price and cost assumptions, applied in the estimation of reserves, the likelihood that a project will achieve commerciality is assumed to be 100 percent, whereas the likelihood of a Contingent Resource achieving commerciality may be less than 100 percent.

**Groundbirch Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves and Net Present Value of Future Net Revenue as of December 31, 2010 (Forecast Prices and Costs)**

| | Proved Developed Producing Reserves (Gross) | Total Proved Reserves (Gross) | Total Proved Plus Probable Reserves (Gross) | Total Proved Plus Probable and Possible Reserves (Gross) |
|---|---|---|---|---|
| Reserves | | | | |
| Gas (Bcf) | 21.5 | 53.1 | 160.9 | 184.8 |
| NGL (MMbbl) | 0.0 | 0.1 | 0.3 | 0.4 |
| Total (MMboe)[(1)] | 3.6 | 9.0 | 27.2 | 31.2 |
| Before tax net present value of future net revenue | | | | |
| 0% discount rate ($MM) | 88.4 | 182.5 | 622.3 | 806.4 |
| 5% discount rate ($MM) | 60.9 | 111.7 | 313.4 | 351.7 |
| 10% discount rate ($MM) | 46.7 | 76.3 | 187.3 | 199.3 |
| 15% discount rate ($MM) | 38.4 | 56.2 | 123.4 | 128.9 |
| 20% discount rate ($MM) | 33.0 | 43.4 | 86.1 | 89.4 |

**Note:**

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

Contingent Resources have been assigned to the remaining areas of the reservoir within the property that meet certain minimum criteria. In order to be classified as a Contingent Resource, a technically feasible recovery project must be defined. These Contingent

Resources are expected to be economic to develop. The reclassification of these Contingent Resources as reserves is contingent upon further reservoir studies, delineation drilling, facility design and preparation of firm development plans, regulatory application approval and company approvals. However, there is no certainty that it will be commercially viable to produce any portion of the Contingent Resource.

| | December 31, 2010 Contingent Resources[1] (Gross) |
|---|---|
| Low estimate[2] | |
| Gas, MMcf | 249.9 |
| NGL, MMbbl | 0.5 |
| Total, MMboe[5] | 42.1 |
| Best estimate[3] | |
| Gas, MMcf | 424.4 |
| NGL, MMbbl | 0.9 |
| Total, MMboe[5] | 71.6 |
| High estimate[4] | |
| Gas, MMcf | 630.7 |
| NGL,s MMbbl | 1.3 |
| Total, MMboe[5] | 106.4 |

**Notes:**

(1) Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. The contingencies may include factors such as economics, legal, environmental, political, regulatory or lack of markets. Contingent Resources are further classified in accordance with the level of certainty associated with the estimates.

(2) A low estimate is a conservative estimate of the quantity of gas that will be recovered from the accumulation, which under probabilistic methodology reflects a ninety percent confidence level.

(3) A best estimate is a best estimate of the quantity of gas that will be recovered from the accumulation, which under probabilistic methodology reflects a fifty percent confidence level.

(4) A high estimate is an optimistic estimate of the quantity of gas that will be recovered from the accumulation, which under probabilistic methodology reflects a ten percent confidence level.

(5) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one barrel of oil.

The accuracy of resource estimates is, in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. These resource volumes are classified as a resource rather than a reserve because they are contingent upon further reservoir studies, delineation drilling and facility design, preparation of firm development plans, regulatory application approval and company approvals. The size of the resource estimate could be positively impacted, potentially in a material amount, if additional delineation wells determine that the aerial extent, reservoir quality and/or the thickness of the reservoir is larger than what is currently estimated based on the interpretation of seismic and well control. The size of the resource estimate could be negatively impacted, potentially in a material amount, if additional delineation wells determine that the aerial extent, reservoir quality and/or the thickness of the reservoir are less than what is currently estimated based on the interpretation of the seismic and well control.

## Forward Contracts

We may use financial derivatives or fixed price contracts to manage our exposure to fluctuations in commodity prices and foreign currency exchange rates. A description of such instruments is provided in notes 20 and 23 of our annual audited consolidated financial statements and related management's discussion and analysis for the year ended December 31, 2010, which may be found on SEDAR at www.sedar.com.

## Additional Information Concerning Abandonment & Reclamation Costs

The total future abandonment and reclamation costs are based on management's estimate of costs to remediate, reclaim and abandon wells and facilities having regard to our Working Interest and the estimated timing of the costs to be incurred in future periods. We have developed a process to calculate these estimates, which considers applicable regulations, actual and anticipated costs, type and size of the well or facility and the geographic location.

GLJ's estimate of downhole well abandonment costs for all properties as well as abandonment costs for all Sable Island offshore and onshore facilities and pipelines upstream of the plant gate are included in their report and therefore in their estimate of future net revenue. All other abandonment and reclamation costs are not reflected in GLJ's estimate of future net revenue.

We have estimated the net present value (discounted at ten percent per annum) of our total asset retirement obligations to be approximately $196 million as at December 31, 2010, based on a total future liability (inflated at 1.5 percent per annum) of approximately $1,790 million. These costs are anticipated to be paid over 50 years with the majority of the costs incurred in the last 20 years and applies to 7,451 net wells (13,723 gross wells).

The following table summarizes our total current asset retirement obligations as at December 31, 2010:

**Asset Retirement Obligations**

| | 2011 ($MM) | 2012 ($MM) | 2013 ($MM) | Remainder ($MM) | Total ($MM) |
|---|---|---|---|---|---|
| Total Abandonment, Reclamation, Remediation & Dismantling | 10.9 | 8.4 | 8.3 | 1,762.8 | 1,790.4 |
| Discounted at ten percent | 10.4 | 7.3 | 6.5 | 171.4 | 195.6 |

The above table excludes asset retirement obligations associated with future development and, in particular, the development associated with Proved Developed Non-Producing, Proved Undeveloped and Probable Reserves, except where such activity would be coincidental with existing operations. GLJ's Proved Developed Producing reserve evaluation is the best comparison to our current operation and includes $230 million ($82 million when discounted at ten percent) of the current asset retirement obligations in the above table. Elsewhere, where we describe Future Net Revenue, only the GLJ estimated abandonment obligation is included in the values. For further clarity, the amount beyond the $230 million or $82 million when discounted at ten percent, is excluded elsewhere.

## Costs Incurred

The following table outlines property acquisition, exploration and development costs that we incurred during the financial year ended December 31, 2010. These costs include only those costs which are cash or cash equivalent.

| Nature of Cost | Amount ($M) |
|---|---|
| Acquisition Costs(1) | |
| Proved | 125,946 |
| Unproved | 464,593 |
| Exploration Costs | 34,058 |
| Development Costs | 295,412 |
| Total | 920,009 |

**Note:**

(1) Based on the values assigned to property, plant and equipment in the purchase price allocation for the Monterey acquisition in the December 31, 2010 financial statements, and cash paid for other properties acquired.

## Exploration and Development Activities

The following table summarizes the number of wells completed or determined to be dry during the financial year ended December 31, 2010.

| | Development | | Exploration | | Total | |
|---|---|---|---|---|---|---|
| **Wells** | Gross | Net | Gross | Net | Gross | Net |
| Gas | 105 | 77.1 | 3 | 2.1 | 108 | 79.2 |
| Oil | 53 | 28.3 | 6 | 4.4 | 59 | 32.7 |
| Service | 39 | 12.0 | 0 | 0.0 | 39 | 12.0 |
| Stratigraphic Test | 0 | 0.0 | 0 | 0.0 | 0 | 0.0 |
| Dry | 6 | 2.7 | 2 | 1.5 | 8 | 4.2 |
| **Total** | 203 | 120.1 | 11 | 8.0 | 214 | 128.1 |

## Production Estimates

The following tables summarize the 2011 average daily volume of gross production estimated by GLJ for all properties held on December 31, 2010 using constant and forecast prices and costs, all of which will be produced in Canada. These estimates assume certain activities take place, such as the development of Undeveloped Reserves, and that there are no dispositions. We estimate our 2011 Company Interest production to be between 74,000 and 76,000 boepd.

**2011 Estimated Production**

| | Constant Prices and Costs | | Forecast Prices and Costs | |
|---|---|---|---|---|
| | Total Proved | Total Proved Plus Probable | Total Proved | Total Proved Plus Probable |
| Light and Medium Crude Oil (bblpd) | 20,766 | 21,538 | 20,766 | 21,538 |
| Heavy Crude Oil (bblpd) | 6,375 | 6,600 | 6,375 | 6,600 |
| Natural Gas (Mcfpd) | 220,667 | 235,897 | 220,667 | 235,897 |
| Natural Gas Liquids (bblpd) | 9,846 | 11,061 | 9,846 | 11,061 |
| **Total (boepd)** | **73,765** | **78,516** | **73,765** | **78,516** |

## Production History (Netback)

The following tables summarize, for each quarter of our most recent financial year, certain of our production information in respect of our Company Interest production, product prices received, royalties paid, operating expenses and resulting operating netbacks.

| | QUARTER ENDED | | | | YEAR ENDED |
|---|---|---|---|---|---|
| | Mar 31, 2010 | June 30, 2010 | Sept 30, 2010 | Dec 31, 2010 | Dec 31, 2010 |
| **Barrels of Oil Equivalent Basis**[1] | | | | | |
| Average Daily Oil Production (boepd) | 75,627 | 75,517 | 72,704 | 74,953 | 74,693 |
| Sales price (after commodity risk management) ($/boe) | 52.49 | 48.75 | 47.07 | 49.01 | 49.34 |
| Other production income ($/boe) | 0.13 | 0.28 | 0.40 | 0.39 | 0.30 |
| Oil & gas sales ($/boe) | 52.62 | 49.03 | 47.47 | 49.40 | 49.64 |
| Processing and other income ($/boe) | 1.06 | 0.47 | 0.65 | 0.84 | 0.76 |
| Royalties ($/boe) | (11.45) | (8.53) | (8.26) | (8.83) | (9.27) |
| Operating expenses ($/boe) | (13.50) | (12.55) | (12.69) | (15.77) | (13.63) |
| Transportation costs ($/boe) | (0.48) | (0.68) | (0.53) | (0.62) | (0.58) |
| Amortization of injectants ($/boe) | (0.67) | (0.58) | (0.52) | (0.44) | (0.55) |
| Operating netback ($/boe) | 27.58 | 27.16 | 26.12 | 24.58 | 26.37 |
| **Light and Medium Crude Oil** | | | | | |
| Average Daily Oil Production (bblpd) | 22,400 | 21,858 | 20,967 | 21,762 | 21,743 |
| Sales price (after commodity risk management) ($/bbl) | 77.35 | 73.84 | 73.93 | 74.98 | 75.04 |
| Other production income ($/bbl) | 0.33 | 0.46 | 0.94 | 0.71 | 0.61 |
| Oil & gas sales ($/bbl) | 77.68 | 74.30 | 74.87 | 75.69 | 75.65 |
| Processing and other income ($/bbl) | 0.58 | 0.37 | 0.34 | 0.60 | 0.47 |
| Royalties ($/bbl) | (18.02) | (18.81) | (15.04) | (17.32) | (17.32) |
| Operating expenses ($/bbl) | (16.62) | (16.01) | (14.01) | (18.81) | (16.39) |
| Transportation costs ($/bbl) | (0.67) | (1.02) | (1.05) | (0.92) | (0.92) |
| Amortization of injectants ($/bbl) | (2.25) | (1.81) | (1.81) | (1.52) | (1.90) |
| Operating netback ($/bbl) | 40.70 | 37.02 | 43.30 | 37.72 | 39.59 |
| **Heavy Crude Oil** | | | | | |
| Average Daily Oil Production (bblpd) | 7,113 | 6,791 | 6,585 | 6,673 | 6,789 |
| Oil & gas sales ($/bbl) | 65.91 | 56.49 | 57.80 | 60.42 | 60.22 |
| Processing and other income ($/bbl) | 1.67 | (2.78) | 1.20 | 0.63 | 0.19 |
| Royalties ($/bbl) | (12.82) | (13.31) | (9.89) | (11.25) | (11.84) |
| Operating expenses ($/bbl) | (16.78) | (12.94) | (17.22) | (16.86) | (15.95) |
| Operating netback ($/bbl) | 37.98 | 27.46 | 31.89 | 32.94 | 32.62 |
| **Natural Gas** | | | | | |
| Average Daily Natural Gas Production (Mcfpd) | 220,641 | 220,856 | 217,711 | 218,044 | 219,301 |
| Sales price (after commodity risk management) ($/Mcf) | 5.62 | 4.86 | 4.67 | 4.87 | 5.00 |
| Other production income ($/Mcf) | 0.01 | 0.05 | 0.04 | 0.06 | 0.04 |
| Oil & gas sales ($/Mcf) | 5.63 | 4.91 | 4.71 | 4.93 | 5.04 |
| Processing and other income ($/Mcf) | 0.25 | 0.21 | 0.15 | 0.21 | 0.20 |
| Royalties ($/Mcf) | (0.87) | (0.07) | (0.45) | (0.31) | (0.42) |
| Operating expenses ($/Mcf) | (1.85) | (1.84) | (1.88) | (2.39) | (2.01) |
| Transportation costs ($/Mcf) | (0.10) | (0.13) | (0.08) | (0.12) | (0.11) |
| Operating netback ($/Mcf) | 3.06 | 3.08 | 2.45 | 2.32 | 2.70 |
| **NGL** | | | | | |
| Average Daily Oil Production (bblpd) | 9,341 | 10,058 | 8,867 | 10,177 | 9,611 |
| Oil & gas sales ($/bbl) | 56.57 | 60.70 | 53.55 | 56.74 | 56.99 |
| Royalties ($/bbl) | (19.15) | (12.57) | (13.77) | (13.97) | (14.80) |
| Operating expenses ($/bbl) | (12.94) | (10.17) | (12.02) | (13.56) | (12.17) |
| Operating netback ($/bbl) | 24.48 | 37.96 | 27.76 | 29.21 | 30.02 |

**Note:**

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six Mcf of natural gas being equal to one boe.

# DESCRIPTION OF CAPITAL STRUCTURE

## General

Our authorized capital consists of an unlimited number of Common Shares and 10,000,000 preferred shares, issuable in series ("**Preferred Shares**"). The following is a summary of the rights, privileges, restrictions and conditions attaching to the securities, which comprise our share capital.

*Common Shares*

Holders of our Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of our Shareholders (other than meetings of a class or series of our shares other than the Common Shares as such). Holders of our Common Shares will be entitled to receive dividends as and when declared by our Board on our Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of our shares ranking in priority to the Common Shares in respect of dividends. Holders of our Common Shares will be entitled in the event of any liquidation, dissolution or winding-up of us, whether voluntary or involuntary, or any other distribution of our assets among our Shareholders for the purpose of winding-up our affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of our shares ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of our shares ranking equally with the Common Shares in respect of return of capital on dissolution, in such of our assets as are available for distribution.

*Preferred Shares*

The Preferred Shares may be issued in one or more series, at any time or from time to time. Before any shares of a particular series are issued, our Board will fix the number of shares that will form such series and will, subject to the limitations set out in the preferred share terms described below, fix the designation, rights, privileges, restrictions and conditions to be attached to the Preferred Shares of such series, including, but without in any way limiting or restricting the generality of the foregoing, the rate, amount or method of calculation of dividends thereon, the time and place of payment of dividends, the consideration for and the terms and conditions of any purchase for cancellation, retraction or redemption thereof, conversion or exchange rights (if any), and whether into or for our securities or otherwise, voting rights attached thereto (if any), the terms and conditions of any share purchase or retirement plan or sinking fund, and restrictions on the payment of dividends on any shares other than Preferred Shares or payment in respect of capital on any of our shares or creation or issue of debt or equity securities; the whole subject to filing of Articles of Amendment setting forth a description of such series including the designation, rights, privileges, restrictions and conditions attached to the shares of such series. Notwithstanding the foregoing: (a) our Board may at any time or from time to time change the rights, privileges, restrictions and conditions attached to unissued shares of any series of Preferred Shares; and (b) 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 will be limited to one vote per Preferred Share at any meeting where the Preferred Shares and Common Shares vote together as a single class.

## Stock Exchange Listings

Our Common Shares are listed and posted for trading on the TSX under the symbol “PGF” and on the NYSE under the symbol “PGH”.

# DIVIDENDS

## General

We currently pay monthly dividends to our Shareholders on the 15th day of each month or the first business day following the 15th day. The record date for any dividend is the last business day of the month preceding the dividend date or such other date as may be determined by our Board. In accordance with stock exchange rules, an ex-dividend date occurs two trading days prior to the record date to permit time for settlement of trades of securities and dividends must be declared a minimum of seven trading days before the record date.

## Historical Distributions/Dividends

Dividends can and may fluctuate in the future. Actual future cash dividends, if any, will be subject to the discretion of our 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, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. We cannot provide assurance that cash flow will be available for distribution to Shareholders in the amounts anticipated or at all. See “*Risk Factors*”.

The following table sets forth distributions declared by the Trust in respect of the preceding three fiscal years on the outstanding Trust Units for the periods indicated, with each amount being paid in the following month:

| Month | 2010 ($) | 2009 ($) | 2008 ($) |
|---|---|---|---|
| January | 0.0700 | 0.1000 | 0.2250 |
| February | 0.0700 | 0.1000 | 0.2250 |
| March | 0.0700 | 0.1000 | 0.2250 |
| April | 0.0700 | 0.1000 | 0.2250 |
| May | 0.0700 | 0.1000 | 0.2250 |
| June | 0.0700 | 0.1000 | 0.2250 |
| July | 0.0700 | 0.1000 | 0.2250 |
| August | 0.0700 | 0.1000 | 0.2250 |
| September | 0.0700 | 0.0700 | 0.2250 |
| October | 0.0700 | 0.0700 | 0.2250 |
| November | 0.0700 | 0.0700 | 0.1700 |
| December | 0.0700 | 0.0700 | 0.1700 |
| **Total** | **0.8400** | **1.0800** | **2.5900** |

## Restrictions on Dividends

Our ability to pay cash dividends to Shareholders may be directly or indirectly affected in certain events as a result of certain restrictions, including restrictions set forth in (i) the credit agreement relating to our Credit Facility and (ii) the note purchase agreements relating to the 2003 US Senior Notes, the 2007 US Senior Notes, the 2008 Senior Notes, the 2010 Senior Notes and the UK Senior Notes; and (iii) the solvency tests in the ABCA. In particular, the funds required to satisfy the interest payable on the foregoing obligations, as well as the amounts payable upon the redemption or maturity of such obligations, as applicable, or upon an Event of Default (as defined below), will be deducted and withheld from the amounts that would otherwise be payable as dividends to Shareholders.

## ABCA Solvency Tests

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 $1 billion.

## Revolving Credit Facility

The credit agreement relating to the Credit Facility stipulates that we shall not make or agree to make cash dividends or other distributions to Shareholders when a “Default” (subject to certain exceptions) or an “Event of Default” has occurred or is continuing or would reasonably be expected to occur as a result of such dividend or distribution. “Events of Default” are defined in the credit agreements to include those events of default typically referred to in a loan agreement of such type and include, among other things; (i) the failure to repay amounts owing under the Credit Facility; (ii) our voluntary or involuntary insolvency; (iii) the default of obligations owing under other debt arrangements; and (iv) a change in control of us. “Default” is defined in the credit agreement to mean any event or circumstance which, with the giving of notice or lapse of time or otherwise, would constitute an Event of Default.

In addition to the standard representations, warranties and covenants commonly contained in a credit facility of this nature, the Credit Facility includes the following key financial covenants:

- The ratio of Consolidated Senior Debt (as defined below) to Consolidated EBITDA (as defined below) at the end of any fiscal quarter shall not exceed 3:1, except upon the completion of a Material Acquisition (as defined below), and for a period extending to the end of the second full fiscal quarter thereafter this limit increases to 3.5:1;
- The ratio of Consolidated Total Debt (as defined below) to Consolidated EBITDA at the end of any fiscal quarter shall not exceed 3.5:1; except upon the completion of a Material Acquisition, and for a period extending to the end of the second full fiscal quarter thereafter, this limit increases to 4:1; and
- The ratio of Consolidated Senior Debt (as defined below) to Total Capitalization (as defined below) shall not exceed 50 percent, except upon the completion of a Material Acquisition, and for a period extending to the end of the second fiscal quarter thereafter, this limit increases to 55 percent.

With respect to the financial covenants, the following definitions apply to the Corporation:

| | |
|---|---|
| Consolidated Senior Debt: | All obligations, liabilities and indebtedness classified as debt on the consolidated balance sheet of the Corporation. |
| Consolidated Total Debt: | The aggregate of Consolidated Senior Debt and Subordinated Debt. |
| Consolidated EBITDA: | The aggregate of the last four fiscal quarters’ net income from operations plus the sum of:<br>• Income taxes;<br>• Interest expense;<br>• All provisions for federal, provincial or other income and capital taxes;<br>• Depreciation, depletion and amortization expense; and<br>• Other non-cash items. |
| Material Acquisition: | An acquisition or series of acquisitions which increases the consolidated tangible assets of Pengrowth by more than five percent. |

| | |
|---|---|
| Subordinated Debt: | Debt which, by its terms, is subordinated to the lenders under the Credit Facility. |
| Total Capitalization: | The aggregate of Consolidated Total Debt and the Shareholders Equity (calculated in accordance with GAAP as shown on the Corporation's consolidated balance sheet). |

### Senior Unsecured Notes

The terms of the note agreements ensure note holders have priority over our Shareholders with respect to our assets and income.

The holders of the US Senior Notes, UK Senior Notes and the Canadian Senior Notes are entitled to certain remedies upon the occurrence of an "Event of Default", which remedies may restrict our ability to pay dividends to Shareholders. An "**Event of Default**" is defined in the note purchase agreements to include those events of default which are typically referred to in a note purchase agreement of a similar nature (including failure to pay principal and interest when due, default in compliance with other covenants, inaccuracy of representations and warranties, cross default to other indebtedness, certain events of insolvency or the rendering of judgments against the Corporation in excess of certain threshold amounts.) "**Default**" is defined in the note agreements to mean any event or circumstance which, after the giving of notice or lapse of time or both, would constitute an Event of Default.

In addition to standard representations, warranties and covenants the note agreements contain the following key financial covenants:

- The ratio of Consolidated EBITDA (as defined below) to interest expense for the four immediately preceding fiscal quarters shall not be less than 4:1;
- With respect to the 2003 US Senior Notes and the UK Senior Notes the Consolidated Total Debt (as defined below) is limited to 60 percent of the Consolidated Total Established Reserves (as defined below) determined and calculated not later then the last day of the first fiscal quarter of the next succeeding fiscal year of the Corporation;
- With respect to the 2010 US Senior Notes, 2008 US Senior Notes, the 2007 US Senior Notes and the CDN Senior Notes the Consolidated Total Debt (as defined below) to Total Capitalization (as defined below) shall not exceed 55 percent at the end of each fiscal quarter; and
- The ratio of Consolidated Total Debt to Consolidated EBITDA for each period of four consecutive fiscal quarters shall not exceed 3.5:1

With respect to these financial covenants, the following definitions apply to the Corporation:

| | |
|---|---|
| Consolidated EBITDA: | The sum of the last four fiscal quarters of (i) net income determined in accordance with GAAP; (ii) all provisions for federal, provincial or other income and capital taxes; (iii) all provisions for depletion, depreciation, and amortization, (iv) interest expense; and (v) non-cash items |
| Consolidated Total Debt: | Has substantially the same meaning as "Consolidated Senior Debt" in the definitions relating to the Credit Facility. |
| Consolidated Total Established Reserves: | The sum of (i) 100 percent of the present value of Pengrowth's Proved Reserves; and (ii) 50 percent of the present value of Pengrowth's Probable Reserves. |
| Total Capitalization: | Consolidated Total Debt plus Shareholder equity in the Corporation |

## 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, Saskatchewan and Nova Scotia, 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 our 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 we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of conditions, legislation, regulations and agreements governing the oil and gas industry.

## Pricing and Marketing

*Oil*

In Canada, oil producers 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, 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 $m^3$/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.

*Natural Gas Liquids*

In Canada, the price of NGL sold in intraprovincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, in part, on the quality of the NGL, prices of competing chemical feed stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms. NGL exported from Canada are 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 criteria prescribed by the NEB and the Government of Canada. NGL may be exported for a term of no more than one year in respect to propane and butane, and no more than two years in respect to ethane, all exports requiring an order of the NEB.

## 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. However, from time to time, pipeline operators will limit the amount of product shipped. A typical reason may be limited ability for purchasers to accept product or there have been limitations imposed due to a pipeline taken out of service for planned or unplanned outages.

## 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, separated from 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 $535/m$^3$ 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 production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

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 $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 oil deep 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 prior to 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 an up to $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 Resources 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 when producing exclusively from coal seams, 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 when producing exclusively from shale seams, 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.

Approximately 67 percent of our Company Interest production forecast for 2011 is in the Province of Alberta on Crown lands.

*British Columbia*

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments at a rate of $3.50 per hectare and make monthly royalty payments in respect of oil and natural gas produced. 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 $m^3$ of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

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

- *Marginal Royalty Reduction Program* providing royalty breaks for low productivity natural gas wells with average monthly production under 25,000 $m^3$ during the first 12 production months and average daily production less than 23 $m^3$ 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 $m^3$ during the first 12 production months and average daily production less than 11.5 $m^3$ (development wells) or 17 $m^3$ (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 discovery subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 $m^3$ of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (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.

Approximately ten percent of our Company Interest production forecast for 2011 is in the Province of British Columbia on Crown lands.

*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 $m^3$ for third and fourth tier oil and $50 per $m^3$ for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a royalty in respect of natural gas production is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), 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 $m^3$ of gas for every $m^3$ of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

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 $m^3$ for third and fourth tier gas and \$35 per thousand $m^3$ for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.**

The 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 $m^3$ for deep development vertical oil wells, 4,000 $m^3$ for non-deep exploratory vertical oil wells and 16,000 $m^3$ for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

- *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 $m^3$ for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 $m^3$ for non-deep horizontal oil wells and 16,000 $m^3$ for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- 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.

Approximately seven percent of our Company Interest production forecast for 2011 is in the Province of Saskatchewan.

*Nova Scotia*

The Government of Nova Scotia has established a generic royalty regime in respect of oil and gas produced from offshore Nova Scotia based on revenues and profits. Such regime contemplates a multi-tier royalty in which the royalty rate fluctuates when certain threshold levels of rates of return on capital have been reached and offers lower royalties for a first project in a new area, being a "high risk project". Notwithstanding the generic royalty regime, royalties in respect of offshore Nova Scotia oil and gas production may be determined contractually between the participant and the Government of Nova Scotia.

Approximately five percent of our Company Interest production forecast for 2011 is in the Province of Nova Scotia.

## 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 government 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 in order 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 or later 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 $CO_2$ equivalent per facility per year for natural gas pipelines; (ii) 3,000 tonnes of $CO_2$ equivalent per facility per year for the upstream oil and gas facility; and (iii) 10,000 boepd per 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 tonnes per $CO_2$ equivalent for the 2010-12 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 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 compliance with the CCEMA. Similarly 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.

Under CCEMA, greenhouse gas emission limits apply once a facility has direct greenhouse gas emissions in a year of 100,000 tonnes CO2 equivalent or more. We currently have two facilities that meet this threshold. Under CCEMA, any facility coming into commercial production after 2000 will be considered a new facility and will be required to reduce its emission intensity (e.g. tonnes of greenhouse gas emitted per unit of production) by 2 percent per year beginning in its fourth year of commercial operation, up to an aggregate 12 percent reduction from the emissions intensity level of its third year of commercial operation.

The CCEMA contains similar compliance mechanisms to those in 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 CO2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. 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.

The Alberta government is expected to raise the price of fund credits and increase the required reductions in greenhouse gas emissions intensity to unspecified levels. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under environmental regulations. Under the Alberta regulations, if the emissions remain at current levels, we would be required to purchase "off-setting" credits in 2010 of up to $300,000 from Alberta Environment. In 2010, our Olds Gas Plant and Judy Creek Gas Conservation Plant did not need to purchase "off-setting" credits as we had a surplus of carbon credits.

*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 CO2 equivalent and rose to $15 per tonne of CO2 equivalent on July 1, 2009 and $20 per tonne of CO2 equivalent on July 1, 2010. It is scheduled to further increase at a rate of $5 per tonne of CO2 equivalent on July 1 of every year until it reaches $30 per tonne of $CO_2$ 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 $CO_2$ equivalent 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 $CO_2$ equivalent per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of $CO_2$ equivalent per year are required to have their emissions reports verified by a third party.

We do not currently have any facilities that emit over 10,000 tonnes of $CO_2$ but we do trigger the Linear Facility definition as we conduct oil and gas extraction and gas processing activities in British Columbia that cumulatively exceed the threshold. As a result, we are required to report our emissions; however, there are no reduction targets proposed for the 2010 reporting year.

*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 upon proclamation. Regulations under 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. At this time this proposed regulation is not expected to have any significant impacts on us or our operations.

*Nova Scotia*

The Province of Nova Scotia has set a goal of lowering greenhouse gas emissions by 10 percent below 1990 levels by 2020 and has implemented the *Environmental Goals and Sustainable Prosperity Act*. The Crown must report annually the amount of reductions achieved in the Province but there is no mechanism for measuring compliance nor are there any consequences for failing to meet the goal.

### General Discussion

As present, we are not paying any direct costs. However, the direct and indirect costs of the various greenhouse gas regulations, existing and proposed, may adversely affect our business, operations and financial results. Equipment that meets future emission standards may not be available on an economic basis and other compliance methods to reduce our emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance or fund credits may not be available for acquisition or may not be available on an economic basis. Any failure to meet emission reduction compliance obligations requirements may materially adversely affect our business and result in fines, penalties and the suspension of operations. There is also a risk that one or more levels of government could impose additional emissions or emissions intensity reduction requirements or taxes on emissions created by us or by consumers of our products. The imposition of such measures might negatively affect our costs and prices for our products and have an adverse effect on earnings and results of operations.

## RISK FACTORS

If any of the following risks occur, our production, revenues and financial condition could be materially impaired, with a resulting decrease in dividends on, and the market price of, our Common Shares. As a result, the trading price of our Common Shares could decline, and you could lose all or part of your investment. **Additional risks are described under the heading "Business Risks" in our Management's Discussion and Analysis for the year ended December 31, 2010.**

**Changes in market-based factors may adversely affect the trading price of the Common Shares.**

The market price of our Common Shares is sensitive to a variety of market based factors including, but not limited to, interest rates, foreign exchange rates and the comparability of the Common Shares to other yield-oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

**Low oil and natural gas prices could have a material adverse effect on our results of operations and financial condition, which, in turn, could negatively affect the amount of dividends to our Shareholders and the market price of the Common Shares.**

The monthly dividends we pay to our Shareholders and the market price of the Common Shares depend, in part, on the prices we receive for our oil and natural gas production. Oil and natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond our control. While oil prices are set in a much broader global market, natural gas prices are largely dependent on North American economies. Additional factors include:

- global energy policy, including the ability of OPEC to set and maintain production levels for oil;
- geo-political conditions;
- worldwide economic conditions;
- weather conditions including weather-related disruptions to the North American natural gas supply;
- the supply and price of foreign oil and natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities;
- the effect of worldwide energy conservation measures; and
- government regulation.

Declines in oil or natural gas prices could have an adverse effect on our operations, financial condition and proved reserves and ultimately on the market price of the Common Shares and our ability to pay dividends to our Shareholders.

**The amount of future dividends, if any, may vary.**

The amount of future cash dividends, if any, will be subject to the discretion of our board of directors and may vary depending on a variety of factors, forecasts and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of our board of directors and management team, we will change our dividend policy from time to time as circumstances warrant and as a result, future cash dividends could be reduced or suspended entirely. The market value of the Common Shares may deteriorate if we reduce or suspend the amount of the cash dividends that we pay in the future and such deterioration may be material. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of our dividends and potential legislative and regulatory changes.

**Dividends may be reduced during periods of lower operating cash flow, which result from lower commodity prices and the decision by us to make capital expenditures using cash flow. A reduction in dividends could also negatively affect the market price of the Common Shares.**

Production and development costs incurred with respect to properties, including power costs and the costs of injection fluids associated with tertiary recovery operations, reduce the income that we receive and, consequently, the amounts we can distribute to our Shareholders.

The timing and amount of capital expenditures will directly affect the amount of income available for dividends to our Shareholders. Dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are planned. To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand oil and gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that we are required to use cash flow to finance capital expenditures or property acquisitions, the cash we receive will be reduced, resulting in reductions to the amount of cash we are able to distribute to our Shareholders. A reduction in the amount of cash distributed to Shareholders may negatively affect the market price of the Common Shares.

**Actual production and reserves will vary from estimates, and those variations could be material and may negatively affect the market price of the Common Shares and dividends to our Shareholders.**

The value of the Common Shares will depend upon, among other things, our reserves. In making strategic decisions, we rely upon reports prepared by our independent reserve engineers and our own internal estimates. Estimating future production and reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for the underlying properties will vary from estimates and those variations could be material. Changes in the prices of, and markets for, oil and natural gas from those anticipated at the time of making such assessments will affect the return on, and value of, our Common Shares. The reserve and cash flow information contained herein represent estimates only. Petroleum engineers consider many factors and make assumptions in estimating reserves.

Those factors and assumptions include:

- historical production from the area compared with production rates from similar producing areas;
- the assumed effect of government regulation;
- assumptions about future commodity prices, exchange rates, production and development costs, capital expenditures, abandonment costs, environmental liabilities, and applicable royalty regimes;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- marketability of production; and
- other government levies that may be imposed over the producing life of reserves.

If any of these factors and assumptions prove to be inaccurate, our actual results may vary materially from our reserve estimates. Many of these factors are subject to change and are beyond our control. In particular, changes in the prices of, and markets for, oil and natural gas from those anticipated at the time of making such assessments will affect the return on, and value of, our Common Shares. In addition, all such assessments involve a measure of geological and engineering uncertainty that could result in lower production and reserves than anticipated. A portion of our reserves are classified as "undeveloped" and are subject to greater uncertainty than reserves classified as "developed".

In accordance with normal industry practices, we engage independent petroleum engineers to conduct a detailed engineering evaluation of our oil and gas properties for the purpose of estimating our reserves as part of our year end reporting process. As a result of that evaluation, we may increase or decrease the estimates of our reserves. We do not consider an increase or decrease in the estimates of our reserves in the range of up to five percent to be material or inconsistent with normal industry practice. Any significant reduction to the estimates of our reserves resulting from any such evaluation could have a material adverse effect on the value of our Common Shares.

**If we are unable to acquire or develop additional reserves, the value of the Common Shares and dividends to our Shareholders may decline.**

Our future oil and natural gas reserves and production, and therefore our cash flow, will depend upon our success in acquiring and/or developing additional reserves. If we fail to add reserves by acquiring or developing them, our reserves and production will decline over time as current reserves are produced. When oil and gas from our properties can no longer be economically produced and marketed, our Common Shares will have no value unless additional reserves have been acquired or developed. If we are not able to raise capital on favourable terms, we may not be able to add to or maintain our reserves. If we use our cash flow to acquire or develop reserves, we will reduce our cash available to be distributed to Shareholders. There is strong competition in all aspects of the oil and gas industry, including reserve acquisitions. We will actively compete for reserve acquisitions and skilled industry personnel with other oil and gas companies and organizations. However, we cannot assure you that we will be successful in acquiring additional reserves on terms that meet our objectives.

Future oil and natural gas exploration may involve unprofitable efforts, not only from unsuccessful wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

**Uncertainty in the credit markets may restrict the availability or increase the cost of borrowing required for future development and acquisitions.**

Uncertainty in domestic and international credit markets could materially affect our ability to access sufficient capital for our capital expenditures and acquisitions and, as a result, may have a material adverse effect on our ability to execute our business strategy and on our financial condition. There can be no assurance that financing will be available or sufficient to meet these requirements or for other corporate purposes or, if financing is available, that it will be on terms appropriate and acceptable to us. Should the lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued resulting in a dilutive effect on current and future Shareholders.

**In the normal course of our business, we have entered into contractual arrangements with third parties that subject us to the risk that such parties may default on their obligations.**

We are exposed to third party credit risk through our contractual arrangements with current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to us, such failures could have a material adverse effect on us and our cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

**Our operation of oil and natural gas wells could subject us to potential environmental claims and liabilities, which will be funded out of our cash flow and will reduce cash flow otherwise available for dividend to Shareholders.**

The oil and natural gas industry is subject to extensive environmental regulation, which imposes restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and gas industry operations. In addition, Canadian legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of this or other legislation may result in fines or the issuance of a clean-up order. Ongoing environmental obligations will be funded out of our cash flow and could therefore reduce the cash available to be distributed to our Shareholders.

**We may be unable to successfully compete with other industry participants, which could negatively affect the market price of the Common Shares and dividends to our Shareholders.**

There is strong competition in all aspects of the oil and gas industry. We will actively compete for capital, skilled personnel, undeveloped lands, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity and in all other aspects of its operations with a substantial number of other organizations. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a world-wide basis and, as such, have greater technical, financial and operational resources than us.

**Incorrect assessments of value at the time of acquisitions could adversely affect the value of our Common Shares and dividends to our Shareholders.**

Acquisitions of oil and gas properties or companies are based in large part on engineering and economic assessments made by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic and engineering uncertainty which could result in lower than anticipated production and reserves.

**Our indebtedness may limit the amount of dividends that we are able to pay our Shareholders, and if we default on our debts, the net proceeds of any foreclosure sale would be allocated to the repayment of our lenders, note holders and other creditors and only the remainder, if any, would be available for dividend to our Shareholders.**

We are indebted under our credit facility and the Notes. Certain covenants in the agreements with our lenders and with respect to the Notes may limit the amount of dividends paid to Shareholders. Variations in interest rates, exchange rates and scheduled principal repayments could result in significant changes in the amount we are required to apply to the service of our outstanding indebtedness. If we become unable to pay our debt service charges or otherwise cause an event of default to occur, our lenders may foreclose on, or sell, our properties. The net proceeds of any such sale will be allocated firstly to the repayment of our lenders and other creditors and only the remainder, if any, would be payable to Shareholders. In addition, we may not be able to refinance some or all of these debt obligations through the issuance of new debt obligations on the same terms, and we may be required to refinance through the issuance of new debt obligations on less favourable terms or through the issuance of additional securities or through other means. In any such event, the amount of cash available for dividend may be diluted or adversely impacted and such dilution or impact may be significant.

**A decline in our ability to market our oil and natural gas production could have a material adverse effect on production levels or on the price received for production, which, in turn, could reduce dividends to our Shareholders and affect the market price of the Common Shares.**

The marketability of our production depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. United States federal and state and Canadian federal and provincial regulation of oil and gas production and transportation, general economic conditions, and changes in supply and demand could adversely affect our ability to produce and market oil and natural gas. If market factors dramatically change, the financial impact on us could be substantial. The availability of markets is beyond our control.

**The operation of a portion of our properties is largely dependent on the ability of third party operators, and harm to their business could cause delays and additional expenses in our receiving revenues, which could negatively affect the market price of the Common Shares and dividends to our Shareholders.**

The continuing production from a property, and to some extent the marketing of production, is dependent upon the ability of the operators of our properties. Approximately 37 percent of our properties are operated by third parties, based on daily production. If, in situations where we are not the operator, the operator fails to perform these functions properly or becomes insolvent, revenues may be reduced. Revenues from production generally flow through the operator and, where we are not the operator; there is a risk of delay and additional expense in receiving such revenues.

The operation of the wells located on properties not operated by us are generally governed by operating agreements which typically require the operator to conduct operations in a good and workman-like manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to us or our Shareholders. As owner of working interests in properties not operated by us, we will generally have a cause of action for damages arising from a breach of the operator's duty. Although not established by definitive legal precedent, it is unlikely that we or our Shareholders would be entitled to bring suit against third party operators to enforce the terms of the operating agreements. Therefore, our Shareholders will be dependent upon us, as owner of the working interest, to enforce such rights.

**Our dividends and the market price of the Common Shares could be adversely affected by unforeseen title defects, which could reduce dividends to our Shareholders.**

Although title reviews are conducted prior to any purchase of significant resource assets, such reviews cannot guarantee that an unforeseen defect in the chain of title will not arise to defeat our title to certain assets. Such defects could reduce the amount of cash flow, possibly resulting in lower dividends to our Shareholders which could result in a lower market price of the Common Shares.

**Fluctuations in foreign currency exchange rates could adversely affect our business, the market price of the Common Shares and dividends to our Shareholders.**

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/United States dollar exchange rate which fluctuates over time. A material increase in the value of the Canadian dollar may negatively impact our net production revenue and cash flow. To the extent that we have engaged, or in the future engage, in risk management activities related to commodity prices and foreign exchange rates, through entry into oil or natural gas price commodity contracts and foreign exchange contracts or otherwise, we may be subject to unfavourable price changes and credit risks associated with the counterparties with which we contract.

A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies in acquiring Canadian oil and gas properties and may make it more difficult for us to replace reserves through acquisitions.

**We may incur material costs as a result of compliance with health, safety and environmental laws and regulations which could negatively affect our financial condition and, therefore, reduce dividends to our Shareholders and decrease the market price of the Common Shares.**

Compliance with environmental laws and regulations could materially increase our costs. We may incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. In particular, we may be required to incur significant costs to comply with legislation and regulations to reduce emissions of greenhouse gases into the air.

**Lower oil and gas prices increase the risk of write-downs of our oil and gas property investments which could be viewed unfavourably in the market or could limit our ability to borrow funds or comply with covenants contained in our current or future credit agreements or other debt instruments.**

Under Canadian accounting rules, the net capitalized cost of oil and gas properties may not exceed a "ceiling limit" which is based, in part, upon estimated future net cash flows from reserves. If the net capitalized costs exceed this limit, we must charge the amount of the excess against earnings. As oil and gas prices decline, our net capitalized cost may approach and, in certain circumstances, exceed this cost ceiling, resulting in a charge against earnings. Under United States accounting rules, the cost ceiling is generally lower than under Canadian rules because the future net cash flows used in the United States ceiling test are based on proven reserves only. Accordingly, we would have more risk of a ceiling test write-down in a declining price environment if we reported under United States generally accepted accounting principles. While these write-downs would not affect cash flow, the charge to earnings could be viewed unfavourably in the market or could limit our ability to borrow funds or comply with covenants contained in our current or future credit agreements or other debt instruments.

**Changes to accounting policies, including the implementation of IFRS, may result in significant adjustments to our financial results, which could negatively impact our business, including increasing the risk of failing a financial covenant contained within our credit facility.**

In January 2006, the CICA Accounting Standards Board ("**AcSB**") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, the AcSB confirmed in February 2008 that IFRS will replace Canadian GAAP in 2011 for Canadian publicly accountable enterprises. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences that must be evaluated. The implementation of IFRS may result in significant adjustments to our financial results, which could negatively impact our business, including increasing the risk of failing a financial covenant contained within our credit facility. At this time, we cannot reasonably quantify the full impact that adopting IFRS will have on our financial position and future results. For information regarding the impact that IFRS will have on our accounting policies and financial statements, see "*International Financial Reporting Standards (**IFRS**)" in* the Annual MD&A and the Third Quarter MD&A, which documents are incorporated by reference herein.

**The ability of investors resident in the United States to enforce civil remedies may be negatively affected for a number of reasons.**

We are an Alberta corporation. We have our principal places of business in Canada. All of our directors and officers are residents of Canada and all or a substantial portion of our assets and of such persons are located outside of the United States. Consequently, it may be difficult for United States investors to affect service of process within the United States upon us or such persons or to realize in the United States upon judgments of courts of the United States predicated upon civil remedies under the United States Securities Act of 1933, as amended. Investors should not assume that Canadian courts:

- will enforce judgments of United States courts obtained in actions against us or such persons predicated upon the civil liability provisions of the United States federal securities laws or the securities or "blue sky" laws of any state within the United States; or
- will enforce, in original actions, liabilities against us or such persons predicated upon the United States federal securities laws or any such state securities or blue sky laws.

**Future acquisitions may result in substantial future dilution of your Common Shares.**

One of our objectives is to continually add to our reserves through acquisitions and through development. Our success is, in part, dependent on our ability to raise capital from time to time. Shareholders may also suffer dilution in connection with future issuances of Common Shares.

**Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States.**

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes; however, we also follow the United States practice of separately reporting these volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves. The SEC permits, but does not require, the disclosure of reserves based on forecast prices and costs.

The documents incorporated by reference herein may include estimates of proved, proved plus probable and possible reserves, as well as resources. The SEC permits, but does not require, the inclusion of estimates of probable and possible reserves in filings made with it by United States oil and gas companies. The SEC does not permit the inclusion of estimates of resources in reports filed with it by United States companies.

**Shareholders who are United States persons face certain income tax risks.**

The United States federal income tax risks related to owning and disposing of our Common Shares include the following:

- A non-United States entity treated as a corporation for United States federal income tax purposes will be a passive foreign investment company ("**PFIC**") if it generates primarily passive income or the greater part of its assets generate, or are held for the production of, passive income. We are currently not a PFIC although no assurance can be given that we will not be a PFIC in 2011 or thereafter. If we were classified as a PFIC, for any year during which a United States Shareholder owns Common Shares, such United States Shareholder would generally be subject to special adverse rules including taxation at maximum ordinary income rates plus an interest charge on both gains on sale and certain dividends. Certain elections may be available to a United States Shareholders if we were classified as a PFIC to alleviate these adverse tax consequences.

**Changes in government regulations that affect the crude oil and natural gas industry could adversely affect us and reduce our dividends to our Shareholders.**

The oil and gas industry in Canada is subject to federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, the exportation of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Government regulations may change from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas or increase our costs, either of which would have a material adverse impact on us.

**Terrorist attacks and the threat of terrorist attacks may have an adverse impact on us.**

Energy sector participants, including us, are a potential target for terrorists. The possibility that infrastructure facilities may be direct targets of, or indirect casualties of, an act of terror and the implementation of security measures as a precaution against possible terrorist attacks may result in increased cost to our business.

**Delays in business operations could adversely affect dividends to Shareholders and the market price of the Common Shares.**

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of cash available for dividend to Shareholders in a given period and expose us to additional third party credit risks.

**Changes in market-based factors may adversely affect the trading price of the Common Shares.**

The market price of our Common Shares is sensitive to a variety of market based factors including, but not limited to, interest rates, foreign exchange rates and the comparability of the Common Shares to other yield-oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

**The industry in which we operate exposes us to potential liabilities that may not be covered by insurance.**

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us. In accordance with industry practice, we are not fully insured against all of these risks, nor are all such risks insurable. Although we maintain liability insurance in an amount that we consider consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects. While we have both safety and environmental policies in place to protect our operators and employees and to meet regulatory requirements in areas where we operate, any costs incurred to repair damages or pay liabilities would reduce the funds available for dividend to the Shareholders.

**If there are delays in our projects, this may delay our expected revenues from operations.**

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that we produce.

**We may be subject to growth-related risks including capacity constraints and pressure on our internal systems and controls.**

Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. Our inability to deal with this growth may have a material adverse effect on our business, financial condition, results of operations and prospects.

Certain of our directors are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions.

Certain of our directors are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA.

**Our success depends in large measure on certain key personnel.**

The loss of the services of key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. The contributions of the existing management team to our immediate and near term operations 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 we will be able to continue to attract and retain all personnel necessary for the development and operation of our business.

## MARKET FOR SECURITIES

Prior to January 3, 2011 the Trust Units were listed on the NYSE under the symbol and "PGH" and prior to January 10, 2011 the Trust Units were listed on the TSX under the symbol "PGF.UN". Our outstanding Common Shares have been listed and posted for trading on the NYSE under the symbol "PGH" since January 3, 2011 and on the TSX under the symbol "PGF" since January 10, 2011. The following tables set forth certain trading information for the Trust Units in 2010 as reported by the TSX and the NYSE.

| | TSX | | |
|---|---|---|---|
| **Trust Units 2010** | **($) High** | **($) Low** | **Volume** |
| January | 11.30 | 10.15 | 10,678,116 |
| February | 11.32 | 10.62 | 7,302,202 |
| March | 11.96 | 11.02 | 15,393,052 |
| April | 12.00 | 11.14 | 10,886,992 |
| May | 11.72 | 8.50 | 11,436,919 |
| June | 10.42 | 8.73 | 11,713,736 |
| July | 10.43 | 9.40 | 19,638,174 |
| August | 10.36 | 9.86 | 11,806,987 |
| September | 11.44 | 10.32 | 18,338,028 |
| October | 12.28 | 11.29 | 13,490,790 |
| November | 13.33 | 11.84 | 41,295,117 |
| December | 13.38 | 12.76 | 15,683,440 |

| | NYSE | | |
|---|---|---|---|
| **Trust Units 2010** | **(US$) High** | **(US$) Low** | **Volume** |
| January | 10.92 | 9.72 | 7,355,078 |
| February | 10.73 | 10.04 | 5,869,870 |
| March | 11.78 | 10.51 | 6,912,854 |
| April | 11.97 | 10.97 | 7,986,861 |
| May | 11.60 | 8.61 | 11,451,681 |
| June | 10.27 | 8.97 | 6,620,949 |
| July | 10.03 | 8.85 | 6,969,592 |
| August | 9.98 | 9.25 | 5,349,184 |
| September | 11.10 | 9.82 | 7,834,570 |
| October | 11.99 | 11.02 | 6,057,204 |
| November | 10.92 | 9.72 | 7,355,078 |
| December | 10.73 | 10.04 | 5,869,870 |

## DIRECTORS AND OFFICERS

The name, jurisdiction of residence, position held and principal occupation for the previous five years of each of our directors and officers are set out below:

| Name and Jurisdiction of Residence | Position with Pengrowth[(1)] | Principal Occupation | Common Shares Controlled or Beneficially Owned[(2)] |
|---|---|---|---|
| John B. Zaozirny[(3)(4)]<br>Alberta, Canada | Chairman and Director<br>(Director since 1988) | Vice Chairman of Canaccord Genuity Corp. since May 2010 and prior thereto Vice Chairman of Canaccord Financial Inc. | 35,100 |
| Derek W. Evans<br>Alberta, Canada | President, Chief Executive Officer and Director<br>(Director since 2009) | President and Chief Executive Officer of Pengrowth since September 2009; prior thereto President and Chief Operating Officer of Pengrowth since May 2009; and prior thereto, the President and Chief Executive Officer of Focus Energy Trust (energy trust) until 2008. | 167,501 |
| Thomas A. Cumming[(4)(5)(6)]<br>Alberta, Canada | Director<br>(Director since 2000) | Business Consultant and Corporate Director. | 8,678 |
| Wayne K. Foo[(3)(5)]<br>Alberta, Canada | Director<br>(Director since 2006) | President and Chief Executive Officer of Parex Resources Inc. (energy company) since 2009; prior thereto President and Chief Executive Officer of Petro Andina Resources Inc. | 5,273 |

| Name and Jurisdiction of Residence | Position with Pengrowth[(1)] | Principal Occupation | Common Shares Controlled or Beneficially Owned[(2)] |
|---|---|---|---|
| James D. McFarland[(5)(6)(7)]<br>Alberta, Canada | Director<br>(Director since 2010) | President and Chief Executive Officer of Valeura Energy Inc. (energy company) and its predecessor PanWestern Energy Inc. since April, 2010; prior thereto President and Chief Executive Officer of Verenex Energy Inc. from March, 2004 to December, 2009. | 15,791 |
| Michael S. Parrett[(3)(4)(6)]<br>Ontario, Canada | Director<br>(Director since 2004) | Business Consultant and Corporate Director. | 4,000 |
| A. Terence Poole[(3)(6)]<br>Alberta, Canada | Director<br>(Director since 2005) | Business Consultant since 2006; prior thereto Executive Vice President, Corporate Strategy and Development at Nova Chemicals Corporation. | 50,000 |
| D. Michael G. Stewart[(4)(5)]<br>Alberta, Canada | Director<br>(Director since 2006) | Corporate Director. | 23,005 |
| Gillian Basford<br>Alberta, Canada | Vice President, Human Resources | Vice President, Human Resources of Pengrowth since January 2011; prior thereto Interim Vice President, Human Resources of Pengrowth Corporation from September 2010 until December 2010; prior thereto independent consultant. | nil |
| Douglas C. Bowles<br>Alberta, Canada | Vice President and Controller | Vice President and Controller of Pengrowth since March 2006. | 41,780 |
| James E.A. Causgrove<br>Alberta, Canada | Vice President, Production and Operations | Vice President, Production and Operations of Pengrowth. | 85,532 |
| William G. Christensen<br>Alberta, Canada | Vice President, Strategic Planning and Reservoir Exploitation | Vice President, Strategic Planning and Reservoir Exploitation of Pengrowth. | 67,855 |
| Steve J. De Maio[(8)]<br>Alberta Canada | Vice President, In-Situ Development & Operations | Vice President In-Situ Development & Operations of Pengrowth since September 2010; prior thereto Vice-President of Project Development at Connacher Oil and Gas Limited (energy company) from November 2006 until September 2010; prior thereto President of De Maio Consulting (consulting company). | 28,207 |
| Brent D. Defosse<br>Alberta, Canada | Vice President, Drilling and Completions | Vice President, Drilling and Completions of Pengrowth since May 2010; prior thereto President of Brennex Resources Ltd. (engineering company). | 6,143 |
| David Dean Evans<br>Alberta, Canada | Treasurer | Treasurer of Pengrowth since February 2009; prior thereto Treasury Manager at ARC Resources Ltd. | 2,060 |
| Andrew D. Grasby<br>Alberta, Canada | Vice President, General Counsel & Corporate Secretary | Vice President, General Counsel & Corporate Secretary of Pengrowth since September 2010; prior thereto a partner with McCarthy Tétrault LLP (law firm). | 4,444 |
| Robert W. Rosine<br>Alberta, Canada | Executive Vice-President, Business Development | Executive Vice President, Business Development of Pengrowth since March 1, 2010; prior thereto President of Mancal Energy Inc. (energy company) from July 2008 to February 2010; prior thereto, Executive Vice President, Corporate Development of Highpine Oil & Gas Limited (energy company) from February 2006 to February 2008; and prior thereto President and Chief Executive Officer of White Fire Energy Ltd. (energy company). | 14,901 |
| Diane J. Shirra<br>Alberta, Canada | Vice President, Montney Gas Development | Vice President, Montney Gas Development of Pengrowth since September, 2010; prior thereto Manager Olds Growth Team with Pengrowth since January 2010; prior thereto Manager Exploitation Engineering, Southern with Pengrowth since 2008; prior thereto Director Rocky Business Unit and Director, Exploration with Canetic Resources Trust (energy trust). | 9,209 |

| Name and Jurisdiction of Residence | Position with Pengrowth(1) | Principal Occupation | Common Shares Controlled or Beneficially Owned(2) |
|---|---|---|---|
| Christopher G. Webster<br>Alberta, Canada | Chief Financial Officer | Chief Financial Officer of Pengrowth. | 204,847 |

**Notes:**

(1) Denotes year first appointed as a director of Pengrowth Corporation, a predecessor of ours. Each of the directors has agreed to serve as such until the next annual meeting of shareholders or until their successor is duly appointed.

(2) As at December 31, 2010 and excluding Common Shares issuable upon the exercise of outstanding rights or deferred entitlement units.

(3) Member of Corporate Governance and Nominating Committee.

(4) Member of Compensation Committee.

(5) Member of Reserves, Operations and Environmental, Health and Safety Committee.

(6) Member of Audit and Risk Committee.

(7) Mr. McFarland was the Managing Director and a director of Southern Pacific Petroleum NL ("**SPP**"), which was listed on the Australian Stock Exchange. In December 2003, a secured creditor of SPP appointed a receiver-manager. Mr. McFarland ceased to be the Managing Director and a director of SPP in February 2004.

(8) Mr. De Maio was formerly an officer and a director of Efficient Energy Resources Ltd. (a private electrical generation company) which agreed to the voluntary appointment of a receiver in 2005.

As at December 31, 2010, the foregoing directors and officers, as a group, beneficially owned, directly or indirectly, 774,326 Common Shares or approximately 0.24 percent of the issued and outstanding Common Shares and held rights and deferred entitlement units to acquire a further 1,803,318 Common Shares. The information as to shares beneficially owned, not being within our knowledge, has been furnished by the respective individuals.

The term of each director expires at the next annual meeting of Shareholders.

## Corporate Cease Trade Orders, Bankruptcies, Personal Bankruptcies, Penalties or Sanctions

No director or executive officer is as at the date hereof, or has been within 10 years of the date hereof, a director or chief executive officer or chief financial officer of any company, including us, that:

(a) while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days; or

(b) was subject to a cease trade or similar order, or an order that denied the relevant company access to any exemption under securities legislation, for a period of more than 30 consecutive days, after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Other than as set out above, no current director or executive officer or securityholder holding a sufficient number of our securities to affect materially our control has, within the last ten years prior to the date hereof, been a director or executive officer of any company (including us) that, while such 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.

In addition, no current director or executive officer or securityholder holding a sufficient number of our securities to affect materially our control has, within the last ten years prior to the date hereof, become bankrupt, 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 director, officer or securityholder.

No current director or executive officer or securityholder holding a sufficient number of our securities to affect materially control of us has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

## AUDIT AND RISK COMMITTEE

The Audit and Risk Committee is appointed annually by our Board of Directors. The responsibilities and duties of the Audit and Risk Committee are set forth in the Audit and Risk Committee Terms of Reference attached hereto as Appendix C. The following table sets forth the name of each of the current members of our Audit and Risk Committee, whether such member is independent and financially literate, as those terms are defined in National Instrument 52-110 *Audit Committees*, and the relevant education and experience of each member:

| Name | Independent | Financially Literate | Relevant Education and Experience |
|---|---|---|---|
| Thomas A. Cumming | Yes | Yes | Mr. Cumming was President and Chief Executive Officer of the Alberta Stock Exchange from 1988 to 1999. His career also includes 25 years with a major Canadian bank both nationally and internationally. He is currently Chairman of Alberta's Electricity Balancing Pool. He is also a past president of the Calgary Chamber of Commerce. Mr. Cumming is a professional engineer and holds a Bachelor of Applied Science degree in Engineering and Business from the University of Toronto. |
| James D. McFarland | Yes | Yes | Mr. McFarland has more than 38 years of experience in the oil and gas industry, most recently as President, Chief Executive Officer, director and co-founder of Valeura Energy Inc., a Toronto Stock Exchange listed issuer. Prior thereto Mr. McFarland was President, Chief Executive Officer, director and a co-founder of Verenex Energy Inc. He has served in senior executive roles as Managing Director of Southern Pacific Petroleum N.L. in Australia, President and Chief Operating Officer of Husky Oil Limited and in a wide range of upstream and corporate functions in an earlier 23-year career with Imperial Oil Limited and other Exxon affiliates in Canada, the US and western Europe. Mr. McFarland is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and the Society of Petroleum Engineers International. Mr. McFarland received a Bachelor of Science in Chemical Engineering from Queen's University and a Master of Science in Petroleum Engineering from the University of Alberta. |
| Michael S. Parrett | Yes | Yes | Mr. Parrett is currently an independent consultant providing advisory service to various companies in Canada and the United States. Mr. Parrett is a director of Stillwater Mining Company, a NYSE listed company. He was formerly Chairman of Gabriel Resources Limited, President of Rio Algom Limited and prior to that Chief Financial Officer of Rio Algom and Falconbridge Limited. Mr. Parrett is a chartered accountant and holds a Bachelor of Arts in Economics from York University. |
| A. Terence Poole | Yes | Yes | Mr. Poole brings extensive senior financial management, accounting, capital and debt market experience to Pengrowth. He retired from Nova Chemicals Corporation in 2006 where he had held various senior management positions including Executive Vice-President, Corporate Strategy and Development. Mr. Poole currently serves on the board of directors for Methanex Corporation. Mr. Poole received a Bachelor of Commerce degree from Dalhousie University and holds a Chartered Accountant designation. |

### Principal Accountant Fees and Services

The following table provides information about the aggregate fees billed to us for professional services rendered by KPMG LLP during fiscal 2010 and 2009:

| | 2010 ($M) | 2009 ($M) |
|---|---|---|
| Audit Fees | 923 | 1,314 |
| Audit Related Fees | - | - |
| Tax Fees | 80 | 208 |
| All Other Fees | - | - |
| **Total** | **1,003** | **1,522** |

*Audit Fees*

Audit fees consist of fees for the audit of our annual financial statements and services that are normally provided in connection with statutory and regulatory filings or engagements.

*Audit-Related Fees*

Audit-related fees normally include due diligence reviews in connection with acquisitions, research of accounting and audit-related issues and the completion of audits required by contracts to which we are a party.

*Tax Fees*

During 2010 and 2009 the services provided in this category included assistance and advice in relation to the preparation of income tax returns for us and our subsidiaries, tax advice and planning and commodity tax consultation.

### Pre-approval Policies and Procedures

Pengrowth has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP. The Audit and Risk Committee approves a schedule which summarizes the services to be provided that the Audit and Risk Committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP. The schedule generally covers the period between the adoption of the schedule and the end of the year, but at the option of the Audit and Risk Committee, may cover a shorter or longer period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the Audit and Risk Committee knows precisely what services it is being asked to pre-approve and (ii) it is not necessary for any member of Pengrowth's management to make a judgment as to whether a proposed service fits within the pre-approved services. Services that arise that were not contemplated in the schedule must be pre-approved by the Audit and Risk Committee chairman or a delegate of the Audit and Risk Committee. The full Audit and Risk Committee is informed of the services at its next meeting.

Pengrowth has not approved any non-audit services on the basis of the *de minimis* exemptions. All non-audit services are pre-approved by the Audit and Risk Committee in accordance with the pre-approval policy referenced herein.

## CONFLICTS OF INTEREST

Our Board of Directors supervises our management of our business and affairs. The Board of Directors approves significant strategic operational decisions and all decisions relating to:

- the issuance of additional Common Shares;
- material acquisitions and dispositions of properties;
- material capital expenditures;
- borrowing; and
- the payment of dividends.

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. The Board of Directors reviews potential conflicts of interest at each meeting. No assurances can be given that opportunities identified by such board members will be provided us.

## LEGAL PROCEEDINGS

We are sometimes named as a defendant in litigation. The nature of these claims is usually related to settlement of normal operational or labour issues. The outcome of such claims against us are not determinable at this time, however they are not expected to have a materially adverse effect on us as a whole. We are not, and have not been at any time within the most recently completed financial year, a party to any legal proceedings, known or contemplated, where the damages involved, excluding interest and costs, exceed ten percent of our assets.

## INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as discussed herein, there are no material interests, direct or indirect, of any of our directors, executive officers, senior officers, any direct or indirect Shareholder who beneficially owns, or who exercises control over, more than 10 percent of our outstanding 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 is reasonably expected to materially affect us.

Prior to July 2009, the Trust was managed by Pengrowth Management Limited. Pursuant to a Management Agreement between Pengrowth Corporation and Pengrowth Management Limited, Pengrowth Management Limited had the right to appoint two directors to the board of directors of Pengrowth Corporation, the administrator of the Trust. Messrs. James Kinnear and Nicholas Villiers were the designated appointees in 2008, 2009 and 2010. Following termination of the Management Agreement in July 2009, Messrs. Kinnear and Villiers remained as directors of Pengrowth Corporation until December 31, 2010.

Mr. John Zaozirny, the Chairman of the Board of Directors, is the Vice Chair of Canaccord Genuity Corporation. Canaccord Genuity Corporation participated as a member of the syndicate of underwriters in connection with the October 23, 2009 equity offering by the Trust of 28,847,000 Trust Units and received a portion of the underwriters' fee from the offering.

Mr. Chris Webster, our Chief Financial Officer, served as a director of Monterey. Mr. Webster did not hold any options in Monterey and abstained from all Monterey board discussions concerning the proposed acquisition of Monterey by Pengrowth.

## INTERESTS OF EXPERTS

As of the date hereof, the directors and officers of GLJ, as a group, beneficially own, directly or indirectly, less than one percent of the outstanding Common Shares.

KPMG LLP are our auditors and have confirmed that they are independent with respect to us within the meaning of the Rules of Professional Conduct of the Alberta Institute of Chartered Accountants.

## AUDITORS, TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal offices in the cities of Montreal, Toronto, Calgary and Vancouver in Canada and Computershare Trust Company, Inc. at its principal office in the City of Golden, Colorado in the United States. Our auditors are KPMG LLP, Chartered Accountants in Calgary, Alberta.

## MATERIAL CONTRACTS

The only material contracts entered into by us or the Trust during the most recently completed financial year, or before the most recently completed financial year and still in effect, other than during the ordinary course of business, are as follows:

(i) the Arrangement Agreement dated November 5, 2010 among the Trust, Pengrowth Corporation, Esprit Energy Trust, Pengrowth Holding Trust, 1552168 Alberta Ltd., Monterey and the Corporation providing for the implementation of the Arrangement, as from time to time amended, supplemented or restated;

(ii) the Amended and Restated Credit Agreement dated January 1, 2011 between Pengrowth and a syndicate of ten financial institutions concerning the Credit Facility;

(iii) the Note Purchase Agreement dated May 11, 2010 concerning the 2010 Senior Notes;

(iv) the Note Purchase Agreement dated August 21, 2008 concerning the 2008 Senior Notes;

(v) the Note Purchase Agreement dated July 26, 2007 concerning the 2007 US Senior Notes;

(vi) the Note Purchase Agreement dated December 1, 2005 concerning the UK Senior Notes; and

(vii) the Note Purchase Agreement dated April 23, 2003 concerning the 2003 US Senior Notes.

Copies of these contracts have been filed by us on SEDAR and are available through the SEDAR website at www.sedar.com.

## CODE OF ETHICS

Pengrowth has adopted a code of ethics, as that term is defined in Form 40-F under the *US Securities Exchange Act of 1934* (the "**Code of Ethics**") that applies to Pengrowth's management, including its Chief Executive Officer, Chief Financial Officer and principal accounting officer. The Code of Ethics is available for viewing on our website www.pengrowth.com under the name "Code of Business Conduct and Ethics", and is available in print to any Shareholder who requests it.

The Board adopted the Code of Ethics on December 16, 2010. The Code of Ethics is substantially similar to the Code of Ethics that was in place for Pengrowth Corporation. All Directors, officers, employees, consultants and contractors are required to accept the Code of Ethics annually.

During the year ended December 31, 2010, Pengrowth has not granted any waivers (including implicit waivers) from the Code of Ethics in respect of its Chief Executive Officer, Chief Financial Officer or its principal accounting officers.

## OFF-BALANCE SHEET ARRANGEMENTS

Pengrowth has no off-balance sheet arrangements.

## DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a Canadian reporting issuer with securities listed on the TSX, Pengrowth has in place a system of corporate governance practices which complies with Canadian securities laws and the TSX corporate governance guidelines as well as the corporate governance rules of the NYSE applicable to foreign private issuers. In the context of its listing on the New York Stock Exchange, Pengrowth is classified as a foreign private issuer and therefore only certain of the NYSE rules are applicable to Pengrowth. However, Pengrowth benchmarks its policies and procedures against major North American entities, with a view to adopting the best practices when appropriate to its circumstances.

The Board of Directors of the Corporation has adopted and published a Corporate Governance Policy which affirms Pengrowth's commitment to maintaining a high standard of corporate governance. This policy is published on Pengrowth's website at www.pengrowth.com. The Board of Directors of the Corporation has also adopted Terms of Reference for each of an Audit and Risk Committee, a Corporate Governance and Nominating Committee, a Compensation Committee, and a Reserves, Operations and Environmental, Health and Safety Committee, a Code of Business Conduct and Ethics, a Corporate Disclosure Policy, an Insider Trading Policy and a Whistleblower Policy each of which is published on Pengrowth's website, and is available in print to any Shareholder who requests it. The Audit and Risk Committee Terms of Reference are attached hereto as Appendix C. From time to time, special committees of the Board of Directors are formed with prescribed mandates.

There is only one significant way in which Pengrowth's corporate governance practices differ from those required to be followed by domestic United States issuers under the NYSE Listed Company Manual. The NYSE Listed Company Manual requires shareholder approval of all equity compensation plans and any material revisions to such plans, regardless of whether the securities to be delivered under such plans are newly issued or purchased on the open market, subject to a few limited exceptions. In contrast, the TSX rules require shareholder approval of equity compensation plans only when such plans involve newly issued securities. If the plan provides a procedure for its amendment, the TSX rules require shareholder approval of amendments only where the amendment involves a reduction in the exercise price or an extension of the term of options held by insiders. As a matter of practice, Pengrowth has obtained the approval of its Shareholders to all of its equity compensation plans, regardless of whether the Common Shares to be delivered under such plans are newly issued or purchased on the open market, with the exception of the Trust Unit Awards Plan which has been used as an employee retention and hiring mechanism when required by the tight employment market in the Canadian oil and gas industry.

## ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, the principal holders of Common Shares and securities authorized for issuance under equity compensation plans, is contained in our Management Information Circular dated March 8, 2011, which relates to the Annual Meeting of Shareholders to be held on May 5, 2011. Additional financial information is contained in our comparative consolidated financial statements and associated management's discussion and analysis for the years ended December 31, 2010 and 2009.

Additional information relating to us may be found on SEDAR at www.sedar.com.

For additional copies of the Annual Information Form and the materials listed in the preceding paragraphs please contact:

Investor Relations

Pengrowth Energy Corporation

Suite 2100, 222 – 3rd Avenue S.W.

Calgary, Alberta T2P 0B4

Telephone: (403) 233-0224

(888) 744-1111

Fax: (866) 341-3586

Website: www.pengrowth.com

E-mail: investorrelations@pengrowth.com

# APPENDIX A

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

To the board of directors of Pengrowth Energy Corporation (the "**Corporation**"):

1. We have prepared an evaluation of the Corporation's reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and 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 board of directors:

| Independent Qualified Reserves Evaluator | Description and Preparation Date of Evaluation Report | Location of Reserves (Country or Foreign Geographic Area) | Net Present Value of Future Net Revenue (before income taxes, 10 percent discount rate - $M) | | | |
|---|---|---|---|---|---|---|
| | | | Audited | Evaluated | Reviewed | **Total** |
| GLJ Petroleum Consultants | January 19, 2011 | Canada | - | 4,636,444 | - | **4,636,444** |

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

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

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:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 7, 2011.

(signed) "*Doug R. Sutton*"
Doug R. Sutton, P.Eng.
Vice President

# APPENDIX B

## FORM 51-101F3
## REPORT OF
## MANAGEMENT AND DIRECTORS
## RESERVES DATA AND OTHER INFORMATION

Management of Pengrowth Energy Corporation (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 will be filed with securities regulatory authorities concurrently with this report.

The Reserves, Operations and Environmental, Health and Safety 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, Operations and Environmental, Health and Safety Committee of the board of directors has reviewed the Corporation's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves, Operations and Environmental, Health and Safety Committee, approved

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

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

(signed) "*Derek W. Evans*"
Derek W. Evans
President and Chief Executive Officer
Pengrowth Energy Corporation

(signed) "*William G. Christensen*"
William G. Christensen
Vice President, Strategic Planning and Reservoir Exploitation
Pengrowth Energy Corporation

(signed) "*Wayne Foo*"
Wayne Foo
Director
Pengrowth Energy Corporation

(signed) "*D. Michael G. Stewart*"
D. Michael G. Stewart
Director
Pengrowth Energy Corporation

March 8, 2011

**APPENDIX C**

**AUDIT AND RISK COMMITTEE**
**TERMS OF REFERENCE**



## OBJECTIVES

The Audit and Risk Committee is appointed by the board of directors (the "**Board**") of Pengrowth Energy Corporation (the "**Corporation**") to assist the Board in fulfilling its oversight responsibilities. The Corporation, together with its subsidiaries and affiliates, are collectively referred to herein as "**Pengrowth**".

The Audit and Risk Committee's primary duties and responsibilities are to:

- monitor the performance of Pengrowth's internal audit function and the integrity of Pengrowth's financial reporting process and systems of internal controls regarding finance, accounting, and legal compliance;
- assist Board oversight of: (i) the integrity of Pengrowth's financial statements; (ii) Pengrowth's compliance with legal and regulatory requirements; and (iii) the performance of Pengrowth's internal audit function and independent auditors;
- monitor the independence, qualification and performance of Pengrowth's external auditors;
- provide an avenue of communication among the external auditors, the internal auditors, management and the Board; and
- oversee Pengrowth's risk management processes.

The Audit and Risk Committee will continuously review and modify its terms of reference with regards to, and to reflect changes in, the business environment, industry standards on matters of corporate governance, additional standards which the Audit and Risk Committee believes may be applicable to Pengrowth's business, the location of Pengrowth's business and its shareholders and the application of laws and policies.

## COMPOSITION

Audit and Risk Committee members must meet the requirements of applicable securities laws and each of the stock exchanges on which the shares of Pengrowth trade. The Audit and Risk Committee will be comprised of three or more directors as determined by the Board. Each member of the Audit and Risk Committee shall be "independent" and "financially literate", as those terms are defined in National Instrument 52-110 *Audit Committees* ("**NI 52-110**") of the Canadian Securities Administrators (as set out in Schedule "A" hereto), Rule 10A-3 promulgated under the *Securities Exchange Act of 1934* (as set out in Schedule "B" hereto), and Section 303A.02 of the New York Stock Exchange Listed Company Manual (as set out in Schedule "C" hereto), as applicable, and as "financially literate" is interpreted by the Board in its business judgement. In addition, at least one member of the Audit and Risk Committee must have accounting or related financial management expertise as defined by paragraph (8) of general instruction B to Form 40-F and as interpreted by the Board in its business judgement.

The members of the Committee shall be appointed by the Board as members of the Committee and shall continue as such until their successors are appointed or until they cease to be directors of the Corporation. At any time, the Board may fill any vacancy in the membership of the Committee.

The chair of the Audit and Risk Committee shall be appointed by the Board. If an Audit and Risk Committee chair is not designated or present at a meeting of the Audit and Risk Committee, the members of the Audit and Risk Committee may designate a chair by majority vote of the Audit and Risk Committee membership.

## MEETINGS AND MINUTES

The Audit and Risk Committee shall meet at least four times annually, or more frequently if determined necessary to carry out its responsibilities.

A meeting may be called by any member of the Audit and Risk Committee, the Board Chairman or the President and Chief Executive Officer ("**CEO**") of Pengrowth. A notice of time and place of every meeting of the Audit and Risk Committee shall be given in writing to each member of the Audit and Risk Committee at least two business days prior to the time fixed for such meeting, unless notice of a meeting is waived by all members entitled to attend. Attendance of a member of the Audit and Risk Committee at a meeting shall constitute waiver of notice of the meeting except where a member attends a meeting for the express purpose of objecting to the transaction of any business on the grounds that the meeting was not lawfully called.

A quorum for meetings of the Audit and Risk Committee shall require a majority of its members present in person or by telephone. If the chair of the Audit and Risk Committee is not present at any meeting of the Audit and Risk Committee, one of the other members of the Audit and Risk Committee present at the meeting will be chosen to preside by a majority of the members of the Audit and Risk Committee present at that meeting.

The Board Chairman and the CEO shall be available to advise the Audit and Risk Committee, shall receive notice of meetings and may attend meetings of the Audit and Risk Committee at the invitation of the chair. Other management representatives, as well as Pengrowth's internal and external auditors, may be invited to attend as necessary. Notwithstanding the foregoing, the chair of the Audit and Risk Committee shall hold *in camera* sessions, without management present, at every meeting of the Committee.

Decisions of the Audit and Risk Committee shall be determined by a majority of the votes cast.

The Audit and Risk Committee shall appoint a member of the Audit and Risk Committee, the Corporate Secretary or another officer of Pengrowth to act as secretary at each meeting for the purpose of recording the minutes of each meeting.

The Audit and Risk Committee shall provide the Board with a summary of all meetings together with a copy of the minutes from such meetings. Where minutes have not yet been prepared, the chair shall provide the Board with oral reports on the activities of the Audit and Risk Committee. All information reviewed and discussed by the Audit and Risk Committee at any meeting shall be referred to in the minutes and made available for examination by the Board upon request to the chair.

## SCOPE, DUTIES AND RESPONSIBILITIES

*MANDATORY DUTIES*

REVIEW PROCEDURES

Pursuant to the requirements of NI 52-110 and other applicable laws, the Audit and Risk Committee will:

1. Review and reassess the adequacy of the Audit and Risk Committee's Terms of Reference at least annually, submit the Terms of Reference to the Board for approval and have the document published annually in Pengrowth's annual information circular and at least every three years in accordance with the regulations of the United States' Securities and Exchange Commission.

2. Prior to filing or public distribution, review, discuss with management and the internal and external auditors and recommend to the Board for approval, Pengrowth's audited annual financial statements, annual earnings press releases, annual information form, all statements including the related management's discussion and analysis required in prospectuses and other offering memoranda, financial statements required by regulatory authorities, all prospectuses and all documents which may be incorporated by reference into a prospectus, including without limitation, the annual information circular. Approve, on behalf of the Board, Pengrowth's interim financial statements and related management's discussion and analysis and interim earnings press releases. This review should include discussions with management, the internal auditors and the external auditors of significant issues regarding accounting principles, practices and judgements. Discuss any significant changes to Pengrowth's accounting principles and any items required to be communicated by the external auditors in accordance with Assurance and Related Services Guideline #11 (AuG-11).

3. Ensure that adequate procedures are in place for the review of Pengrowth's public disclosure of financial information extracted or derived from Pengrowth's financial statements, other than the public disclosure referred to in paragraph 2 above and periodically assess the adequacy of those procedures.

4. Be responsible for reviewing the disclosure contained in Pengrowth's annual information form as required by Form 52-110F1 *Audit Committee Information Required in an AIF*, attached to NI 52-110. If proxies are solicited for the election of directors of Pengrowth, the Audit and Risk Committee shall be responsible for ensuring that Pengrowth's information circular includes a cross-reference to the sections in Pengrowth's annual information form that contain the information required by Form 52-110F1.

EXTERNAL AUDITORS

1. The Audit and Risk Committee shall advise the external auditors of their accountability to the Audit and Risk Committee and the Board as representatives of Pengrowth’s shareholders to whom the external auditors are ultimately responsible. The external auditors shall report directly to the Audit and Risk Committee. The Audit and Risk Committee is directly responsible for overseeing the work of the external auditors, shall review at least annually the independence and performance of the external auditors and shall annually recommend to the Board the appointment of the external auditors or approve any discharge of auditors when circumstances warrant. The Audit and Risk Committee shall, on an annual basis, obtain and review a report by the external auditor describing: (i) the external auditor's internal quality-control procedures; (ii) any material issues raised by the most recent internal quality-control review, or peer review, of the external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the external auditors, and any steps taken to deal with any such issues; and (iii) all relationships between the independent auditor and Pengrowth.

2. Approve the fees and other compensation to be paid to the external auditors.

3. Pre-approve all services to be provided to Pengrowth or its subsidiary entities by Pengrowth's external auditors and all related terms of engagement.

OTHER AUDIT AND RISK COMMITTEE RESPONSIBILITIES

1. Establish procedures for: (i) the receipt, retention and treatment of complaints received by Pengrowth regarding accounting, internal accounting controls, or auditing matters; and (ii) the confidential and anonymous submission by employees of Pengrowth of concerns regarding questionable accounting or auditing matters.

2. Review and approve Pengrowth's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of Pengrowth.

*DISCRETIONARY DUTIES*

The Audit and Risk Committee's responsibilities may, at the Audit and Risk Committee's discretion, also include the following:

REVIEW PROCEDURES

1. In consultation with management, the internal auditors and the external auditors, consider the integrity of Pengrowth's financial reporting processes and controls and the performance of Pengrowth's internal financial accounting staff; discuss significant financial risk exposures and the steps management has taken to monitor, control and report such exposures; and review significant findings prepared by the internal or external auditors together with management's responses.

2. Review, with financial management, the internal auditors and the external auditors, Pengrowth's policies relating to risk management and risk assessment.

3. Meet separately with each of management, the internal auditors and the external auditors to discuss difficulties or concerns, specifically: (i) any difficulties encountered in the course of the audit work, including any restrictions on the scope of activities or access to requested information, and any significant disagreements with management; (ii) any changes required in the planned scope of the audit; and (iii) the responsibilities, budget, and staffing of the internal audit function, and report to the Board on such meetings.

4. Conduct an annual performance evaluation of the Audit and Risk Committee.

INTERNAL AUDITORS

1. Review the annual audit plans of the internal auditors.

2. Review the significant findings prepared by the internal auditors and recommendations issued by any external party relating to internal audit issues, together with management's response.

3. Review the adequacy of the resources of the internal auditors to ensure the objectivity and independence of the internal audit function.

4. Consult with management on management's appointment, replacement, reassignment or dismissal of the internal auditors.

5. Ensure that the internal auditors have access to the Board Chairman and the President and CEO.

EXTERNAL AUDITORS

1. On an annual basis, the Audit and Risk Committee should review and discuss with the external auditors all significant relationships they have with Pengrowth that could impair the auditors' independence.

2. The Audit and Risk Committee shall review the external auditors audit plan – discuss scope, staffing, locations, and reliance upon management and general audit approach.

3. Consider the external auditors' judgments about the quality and appropriateness of Pengrowth's accounting principles as applied in its financial reporting.

4. Be responsible for the resolution of disagreements between management and the external auditors regarding financial performance.

5. Ensure compliance by the external auditors with the requirements set forth in National Instrument 52-108 *Auditor Oversight*.

6. Ensure that the external auditors are participants in good standing with the Canadian Public Accountability Board ("**CPAB**") and participate in the oversight programs established by the CPAB from time to time and that the external auditors have complied with any restrictions or sanctions imposed by the CPAB as of the date of the applicable auditor's report relating to Pengrowth's annual audited financial statements.

7. Monitor compliance with the lead auditor rotation requirements of Regulation S-X.

RISK MANAGEMENT POLICIES

Review and recommend for approval by the Board changes considered advisable, after consultation with officers of the Corporation, to the Corporation's policies relating to:

(a) The risks inherent in the Corporation's businesses, facilities, strategic direction;

(b) The overall risk management strategies (including insurance coverage);

(c) The risk retention philosophy and the resulting uninsured exposure of the Corporation; and

(d) The loss prevention policies, risk management and hedging programs, and standard and accountabilities of the Corporation in the context of competitive and operational considerations.

RISK MANAGEMENT PROCESSES

Review with management at least annually the Corporation's processes to identify, monitor, evaluate and address important enterprise-wide business risks.

FINANCIAL RISK MANAGEMENT

Review with management activity related to management of financial risks to the Corporation.

OTHER AUDIT AND RISK COMMITTEE RESPONSIBILITIES

1. On at least an annual basis, review with Pengrowth's legal counsel any legal matters that could have a significant impact on the organization's financial statements, Pengrowth's compliance with applicable laws and regulations, and inquiries received from regulators or governmental agencies.

2. Annually prepare a report to shareholders as required by the United States' Securities and Exchange Commission; the report should be included in Pengrowth's annual information circular.

3. Ensure due compliance with each obligation to certify, on an annual and interim basis, internal control over financial reporting and disclosure controls and procedures in accordance with applicable securities laws and regulations.

4. Review all exceptions to established policies, procedures and internal controls of Pengrowth, which have been approved by any two officers of Pengrowth.

5. Perform any other activities consistent with this Charter, Pengrowth's by-laws, and other governing law as the Audit and Risk Committee or the Board deems necessary or appropriate.

6. Maintain minutes of meetings and periodically report to the Board on significant results of the foregoing activities.

## COMMUNICATION, AUTHORITY TO ENGAGE ADVISORS AND EXPENSES

The Audit and Risk Committee shall have direct access to such officers and employees of Pengrowth, to Pengrowth's internal and external auditors and to any other consultants or advisors, as well as to such information respecting Pengrowth it considers necessary to perform its duties and responsibilities.

Any employee may bring before the Audit and Risk Committee, on a confidential basis, any concerns relating to matters over which the Audit and Risk Committee has oversight responsibilities.

The Audit and Risk Committee has the authority to engage the external auditors, independent legal counsel and other advisors as it determines necessary to carry out its duties and to set the compensation for any auditors, counsel and other advisors, such engagement to be at Pengrowth's expense. Pengrowth shall be responsible for all other expenses of the Audit and Risk Committee that are deemed necessary or appropriate by the Audit and Risk Committee in order to carry out its duties.

Adopted by the Board of Pengrowth on March 8, 2011.

**Schedule "A"**
**Excerpt from Multilateral Instrument 52-110**
**Standard of "Independence"**

1. An audit committee member is independent if he or she has no direct or indirect material relationship with Pengrowth.

2. For the purposes of paragraph 1, a "material relationship" is a relationship which could, in the view of the Board, be reasonably expected to interfere with the exercise of a member's independent judgment.

3. Despite paragraph 2, the following individuals are considered to have a material relationship with Pengrowth:

    (a) an individual who is, or has been within the last three years, an employee or executive officer of Pengrowth;

    (b) an individual whose immediate family member is, or has been within the last three years, an executive officer of Pengrowth;

    (c) an individual who:

        (i) is a partner of a firm that is Pengrowth's internal or external auditor,

        (ii) is an employee of that firm, or

        (iii) was within the last three years a partner or employee of that firm and personally worked on Pengrowth's audit within that time;

    (d) an individual whose spouse, minor child or stepchild, or child or stepchild who shares a home with the individual:

        (i) is a partner of a firm that is Pengrowth's internal or external auditor,

        (ii) is an employee of that firm and participates in its audit, assurance or tax compliance (but not tax planning) practice, or

        (iii) was within the last three years a partner or employee of that firm and personally worked on Pengrowth's audit within that time;

    (e) an individual who, or whose immediate family member, is or has been within the last three years, an executive officer of an entity if any of Pengrowth's current executive officers serves or served at that same time on the entity's compensation committee; and

    (f) an individual who received, or whose immediate family member who is employed as an executive officer of Pengrowth received, more than $75,000 in direct compensation from the issuer during any 12 month period within the last three years.

4. For the purposes of paragraphs 3(c) and 3(d), a partner does not include a fixed income partner whose interest in the firm that is the internal or external auditor is limited to the receipt of fixed compensation (including deferred compensation) for prior service with that firm if the compensation is not contingent in any way on continued service.

5. For the purposes of paragraph 3(f), direct compensation does not include

    (a) remuneration for acting as a member of the Board or any Board committee of Pengrowth, and

    (b) the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with Pengrowth if the compensation is not contingent in any way on continued service.

6. Despite paragraph 3, an individual will not be considered to have a material relationship with Pengrowth solely because the individual or his or her immediate family member

   (a) has previously acted as an interim chief executive officer of Pengrowth, or

   (b) acts, or has previously acted, as a chair or vice-chair of the Board or of any Board committee of Pengrowth on a part-time basis.

7. Despite any determination made under paragraphs 1 through 6, an individual who

   (a) accepts, directly or indirectly, any consulting, advisory or other compensatory fee from Pengrowth or any subsidiary entity of Pengrowth, other than as remuneration for acting in his or her capacity as a member of the Board or any Board committee, or as a part-time chair or vice-chair of the Board or any Board committee; or

   (b) is an affiliated entity of Pengrowth or any of its subsidiary entities,

   is considered to have a material relationship with Pengrowth.

8. For the purposes of paragraph 7, the indirect acceptance by an individual of any consulting, advisory or other compensatory fee includes acceptance of a fee by

   (a) an individual's spouse, minor child or stepchild, or a child or stepchild who shares the individual's home; or

   (b) an entity in which such individual is a partner, member, an officer such as a managing director occupying a comparable position or executive officer, or occupies a similar position (except limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity) and which provides accounting, consulting, legal, investment banking or financial advisory services to Pengrowth or any subsidiary entity of Pengrowth.

9. For the purposes of paragraph 7, compensatory fees do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with Pengrowth if the compensation is not contingent in any way on continued service.

**Standard of "Financial Literacy"**

An individual is financially literate if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by Pengrowth's financial statements.

**Schedule "B"**
**Excerpts from Rule 10A-3 of the Securities and Exchange Act of 1934**
**Standard of "Independence"**

b. *Required standards.*

1. *Independence*.

   i. Each member of the audit committee must be a member of the board of directors of the listed issuer, and must otherwise be independent; provided that, where a listed issuer is one of two dual holding companies, those companies may designate one audit committee for both companies so long as each member of the audit committee is a member of the board of directors of at least one of such dual holding companies.

   ii. *Independence requirements for non-investment company issuers.* In order to be considered to be independent for purposes of this paragraph (b)(1), a member of an audit committee of a listed issuer that is not an investment company may not, other than in his or her capacity as a member of the audit committee, the board of directors, or any other board committee:

      A. Accept directly or indirectly any consulting, advisory, or other compensatory fee from the issuer or any subsidiary thereof, provided that, unless the rules of the national securities exchange or national securities association provide otherwise, compensatory fees do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the listed issuer (provided that such compensation is not contingent in any way on continued service); or

      B. Be an affiliated person of the issuer or any subsidiary thereof.

e. *Definitions*. Unless the context otherwise requires, all terms used in this section have the same meaning as in the Act. In addition, unless the context otherwise requires, the following definitions apply for purposes of this section:

1.

   i. The term *affiliate* of, or a person *affiliated* with, a specified person, means a person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, the person specified.

   ii.

      A. A person will be deemed not to be in control of a specified person for purposes of this section if the person:

         1. Is not the beneficial owner, directly or indirectly, of more than 10% of any class of voting equity securities of the specified person; and

         2. Is not an executive officer of the specified person.

      B. Paragraph (e)(1)(ii)(A) of this section only creates a safe harbor position that a person does not control a specified person. The existence of the safe harbor does not create a presumption in any way that a person exceeding the ownership requirement in paragraph (e)(1)(ii)(A)(1) of this section controls or is otherwise an affiliate of a specified person.

   iii. The following will be deemed to be affiliates:

      A. An executive officer of an affiliate;

      B. A director who also is an employee of an affiliate;

C. A general partner of an affiliate; and

D. A managing member of an affiliate.

iv. For purposes of paragraph (e)(1)(i) of this section, dual holding companies will not be deemed to be affiliates of or persons affiliated with each other by virtue of their dual holding company arrangements with each other, including where directors of one dual holding company are also directors of the other dual holding company, or where directors of one or both dual holding companies are also directors of the businesses jointly controlled, directly or indirectly, by the dual holding companies (and, in each case, receive only ordinary-course compensation for serving as a member of the board of directors, audit committee or any other board committee of the dual holding companies or any entity that is jointly controlled, directly or indirectly, by the dual holding companies).

4. The term control (including the terms controlling, controlled by and under common control with) means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract, or otherwise.

8. The term indirect acceptance by a member of an audit committee of any consulting, advisory or other compensatory fee includes acceptance of such a fee by a spouse, a minor child or stepchild or a child or stepchild sharing a home with the member or by an entity in which such member is a partner, member, an officer such as a managing director occupying a comparable position or executive officer, or occupies a similar position (except limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity) and which provides accounting, consulting, legal, investment banking or financial advisory services to the issuer or any subsidiary of the issuer.

**Schedule "C"**
**Excerpts from Section 303A.00 of the New York Stock Exchange Listed Company Manual**
**303A.02 "Independence" Tests**

The NYSE Listed Company Manual contains the following provisions regarding the independence requirements of members of the audit committee:

(a) No director qualifies as "independent" unless the board of directors affirmatively determines that the director has no material relationship with the listed company (either directly or as a partner, shareholder or officer of an organization that has a relationship with the company). Companies must identify which directors are independent and disclose the basis for that determination.

(b) In addition, a director is not independent if:

(i) The director is, or has been within the last three years, an employee of the listed company, or an immediate family member is, or has been within the last three years, an executive officer, of the listed company.

(ii) The director has received, or has an immediate family member who has received, during any twelve-month period within the last three years, more than $120,000 in direct compensation from the listed company, other than director and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service).

(iii) (A) The director is a current partner or employee of a firm that is the company's internal or external auditor; (B) the director has an immediate family member who is a current partner of such a firm; (C) the director has an immediate family member who is a current employee of such a firm and personally works on the listed company's audit; or (D) the director or an immediate family member was within the last three years a partner or employee of such a firm and personally worked on the listed company's audit within that time.

(iv) The director or an immediate family member is, or has been within the last three years, employed as an executive officer of another company where any of the listed company's present executive officers at the same time serves or served on that company's compensation committee.

(v) The director is a current employee, or an immediate family member is a current executive officer, of a company that has made payments to, or received payments from, the listed company for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of $1 million, or 2% of such other company's consolidated gross revenues.

***General Commentary to Section 303A.02(b):***

An "immediate family member" includes a person's spouse, parents, children, siblings, mothers and fathers-in-law, sons and daughters-in-law, brothers and sisters-in-law, and anyone (other than domestic employees) who shares such person's home. When applying the look-back provisions in Section 303A.02(b), listed companies need not consider individuals who are no longer immediate family members as a result of legal separation or divorce, or those who have died or become incapacitated.

For the purposes of Section 303A, the term "executive officer" has the same meaning specified for the term "officer" in Rule 16a-1(f) under the Securities Exchange Act of 1934 as follows:

> The term "officer" shall mean an issuer's president, principal financial officer, principal accounting officer (or, if there is no such accounting officer, the controller), any vice-president of the issuer in charge of a principal business unit, division or function (such as sales, administration or finance), any other officer who performs a policy-making function, or any other person who performs similar policy-making functions for the issuer. Officers of the issuer's parent(s) or subsidiaries shall be deemed officers of the issuer if they perform such policy-making functions for the issuer. In addition, when the issuer is a limited partnership, officers or employees of the general partner(s) who perform policy-making functions for the limited partnership are deemed officers of the limited partnership.