PENGROWTH ENERGY Corp
Form 40-F
February 28, 2012
Table of Contents

U.S. SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 40-F

¨ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934.**

x **ANNUAL REPORT PURSUANT TO SECTION 13(a) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended: December 31, 2011 **Commission File Number: 1-31253**

PENGROWTH ENERGY CORPORATION

(Exact name of Registrant as specified in its charter)

Alberta, Canada

(Province or other jurisdiction of incorporation or organization)

1311	**None**
(Primary Standard Industrial Classification Code Number)	**(I.R.S. Employer Identification Number)**

Suite 2100, 222 Third Avenue S.W.

Calgary, Alberta Canada T2P 0B4

(403) 233-0224

(Address and telephone number of Registrant s principal executive offices)

Puglisi & Associates

850 Library Avenue, Suite 204

Newark, Delaware 19711

(302) 738-6680

(Name, address (including zip code) and telephone number (including area code)

of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act.

Title of each class	**Name of each exchange on which registered**
Common Shares	New York Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act.

None

(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act.

None

(Title of Class)

For Annual Reports indicate by check mark the information filed with this Form:

x Annual information form x Audited annual financial statements

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report:

There were 360,282,162 Common Shares, of no par value, outstanding as of December 31, 2011.

Indicate by check mark whether the Registrant filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the Exchange Act). If Yes is marked, please indicate the filing number assigned to the Registrant in connection with such Rule. Yes ¨ No x

Indicate by check mark whether the Registrant (1) has filed all reports to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files). Yes ¨ No ¨

This Annual Report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, the registrant s Registration Statements on Form F-10 and F-3 (File Nos. 333-171682 and 333-171672, respectively) under the Securities Act of 1933, as amended.

Table of Contents

DOCUMENTS FILED AS PART OF THIS ANNUAL REPORT

The following documents have been filed as part of this Annual Report on Form 40-F as Appendices hereto:

Appendix	Documents
A	Pengrowth Energy Corporation Annual Information Form for the year ended December 31, 2011.
B	Management s Discussion and Analysis.
C	Financial Statements of Pengrowth Energy Corporation, including Management s Report to Shareholders and the Auditors Reports.
D	Supplemental Unaudited Disclosures about Oil and Gas Producing Activities required under United States Generally Accepted Accounting Principles.
E	Pengrowth Energy Corporation Code of Business Conduct and Ethics dated November 4, 2011.

CERTIFICATIONS AND DISCLOSURE REGARDING CONTROLS AND PROCEDURES

Certifications. See Exhibits 99.3, 99.4, 99.5 and 99.6 to this Annual Report on Form 40-F.

Disclosure Controls and Procedures. The required disclosure is included in the section entitled Disclosure Controls and Procedures contained in the Registrant s Management s Discussion and Analysis for the fiscal year ended December 31, 2011, filed as part of this Annual Report on Form 40-F.

Management s Annual Report on Internal Control Over Financial Reporting. The required disclosure is included in the section entitled Internal Control Over Financial Reporting contained in the Registrant s Management s Discussion and Analysis for the fiscal year ended December 31, 2011, filed as part of this Annual Report on Form 40-F.

Attestation Report of the Registered Public Accounting Firm. The required disclosure is included in the Auditors Report that accompanies the Registrant s Consolidated Financial Statements for the fiscal year ended December 31, 2011, filed as part of this Annual Report on Form 40-F.

Changes in Internal Control Over Financial Reporting. During the fiscal year ended December 31, 2011, there were no changes in the Registrant s internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Registrant s internal control over financial reporting.

NOTICES PURSUANT TO REGULATION BTR

None.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Registrant has a separately-designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The members of the audit committee are: Thomas A. Cumming, James D. McFarland, Michael S. Parrett and A. Terence Poole.

AUDIT COMMITTEE FINANCIAL EXPERT

The board of directors of the Registrant has determined that each of Michael S. Parrett and A. Terence Poole, members of the Registrant s audit committee, qualify as audit committee financial experts for purposes of paragraph (8) of General Instruction B to Form 40-F. The board of directors has further determined that each of Mr. Parrett and Mr. Poole is also independent, as that term is defined in the Corporate Governance Listing Standards of the New York Stock Exchange. The Commission has indicated that the designation of each of Mr. Parrett and Mr. Poole as an audit committee financial expert does not make either of them an expert for any purpose, impose any duties, obligations or liabilities on them that are greater than those imposed on members of the audit committee and the board of directors who do not carry this designation or affect the duties, obligations or liabilities of any other member of the audit committee or the board of directors.

Table of Contents

ADDITIONAL DISCLOSURE

Code of Ethics.

The Registrant has adopted a code of ethics (as that term is defined in Form 40-F), entitled the Code of Business Conduct and Ethics , that applies to all of its employees, including its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions.

On November 4, 2011, the Board of Directors of the Registrant amended the code of ethics to, among other things: indicate that members are expected to read, understand and adhere to the Registrant s Anti-Corruption Policy, Environmental, Health and Safety Policies and Procedures, Corporate Disclosure Policy, Confidentiality Agreements, Policy on Trading in Securities and Acceptable Use Policy for Information System Assets; clarify that members must report to the General Counsel any personal financial interest in, or position in which he or she could derive a benefit or interest from, a business transaction with the Registrant; explicitly state that members are prohibited from taking for themselves opportunities that arise through the use of corporate property, information or position and from using corporate property, information or position for personal gain; indicate that members should neither accept nor offer any gift or entertainment if it will unfairly influence a business relationship; refine the Registrant s policy with respect to political contributions, by stating that political activities should not be conducted on the Company s time or involve the use of any of the Registrant s resources, and that members will not be reimbursed for personal political contributions; refine complaint procedures for the prompt reporting of accounting, financial reporting and auditing matters and other violations of the code of ethics; indicate that members with any question of appropriateness in a particular situation, areas of conflict or disagreement with any aspect of the code of ethics or any applicable laws should discuss the matter with the CEO, Chief Financial Officer, General Counsel or Chairman of the Board of the Registrant; and indicate that no provision of the code of ethics will be waived in respect of a director or executive officer unless expressly approved by the Board of Directors, and that any such waiver shall be disclosed to the Registrant s shareholders.

The description above is qualified in its entirety by reference to the amended Code of Conduct, which is attached hereto as Appendix E and incorporated herein by reference.

The Code of Business Conduct & Ethics is available for viewing on the registrant s website at www.pengrowth.com.

Principal Accountant Fees and Services.

The required disclosure is included under the heading Principal Accountant Fees and Services at page 56 of the Registrant s Annual Information Form for the fiscal year ended December 31, 2011, filed as part of this Annual Report on Form 40-F in Appendix A.

Pre-Approval Policies and Procedures.

The required disclosure is included under the heading Pre-approval Policies and Procedures at page 57 of the Registrant s Annual Information Form for the fiscal year ended December 31, 2011, filed as part of this Annual Report on Form 40-F in Appendix A.

Off-Balance Sheet Arrangements.

The required disclosure is included under the heading Off-Balance Sheet Arrangements at page 58 of the Registrant s Annual Information Form for the fiscal year ended December 31, 2011, filed as part of this Annual Report on Form 40-F in Appendix A.

Tabular Disclosure of Contractual Obligations.

The required disclosure is included under the heading Commitments and Contractual Obligations at page 30 of the Registrant s Management s Discussion and Analysis for the fiscal year ended December 31, 2011, filed as part of this Annual Report on Form 40-F in Appendix B.

UNDERTAKING

Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

Form F-X signed by the Registrant and its agent for service of process has been filed with the Commission together with Form F-10 (333-171682) in connection with its securities registered on such form.

Any changes to the name or address of the agent for service of process of the Registrant shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of the Registrant.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 28, 2012

PENGROWTH ENERGY CORPORATION

By: /s/ Derek W. Evans
Name: (signed) Derek W. Evans
Title: President and Chief Executive Officer

Table of Contents

APPENDIX A

PENGROWTH ENERGY CORPORATION ANNUAL INFORMATION FORM FOR THE YEAR

ENDED DECEMBER 31, 2011

Table of Contents

PENGROWTH ENERGY CORPORATION

ANNUAL INFORMATION FORM

For the year ended December 31, 2011

February 28, 2012

Table of Contents

TABLE OF CONTENTS

Table of Contents

Unless otherwise indicated, all of the information provided in this Annual Information Form is as at December 31, 2011.

Table of Contents

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 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 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 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 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 under the 2005 Note Purchase Agreements; and

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

Engineering

Bitumen Initially-In-Place or **BIIP** refers to that quantity of bitumen that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of BIIP includes production, reserves and Contingent Resources; the remainder is unrecoverable;

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, 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. 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;

Discovered Petroleum Initially-In-Place or **DPIIP** refers to that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of DPIIP includes production, reserves and Contingent Resources; the remainder is unrecoverable;

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 February 27, 2012 with an effective date of December 31, 2011;

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 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 (e.g. when compared to the cost of drilling a well) to put the reserves on production; the developed category may be subdivided into Proved Developed Producing Reserves and Developed Non-Producing Reserves;

Proved Reserves 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;

Table of Contents

Reserve Life Index or **RLI** refers to the number of years determined by dividing Company Interest reserves of a property by the 2012 Company Interest estimated production for the corresponding reserve category from such property. The reserves and the 2012 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 recoverable from known accumulations, as of a given date, 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(s) 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 Petroleum Initially-In-Place or **TPIIP** refers to that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered;

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 Interests, held by Pengrowth in an oil and gas property.

Abbreviations

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

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;

Cdn$ refers to Canadian dollars;

CO_2 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;

F&D Costs refers to finding and development costs;

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

GHG refers to greenhouse gas;

IFRS refers to International Financial Reporting Standards;

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;

Table of Contents

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;

US$ refers to United States dollars;

US GAAP refers to United States generally accepted accounting principles;

WCSB refers to the Western Canadian Sedimentary Basin; and

WTI refers to West Texas Intermediate crude oil.

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 (6) Mcf of natural gas to one barrel of oil and a Mcfe conversion ratio of one barrel of oil to six (6) 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. In addition, given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

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

Table of Contents

PRESENTATION OF OUR FINANCIAL INFORMATION

Financial information in this Annual Information Form has been prepared in accordance with International Financial Reporting Standards (**IFRS**). IFRS differs in some significant respects from United States generally accepted accounting principles (**US GAAP**) and thus our financial statements may not be comparable to the financial statements of companies following US GAAP.

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 Reserves 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 , 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 2012 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 2012 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,

Table of Contents

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, 2011, 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.

Table of Contents

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 24, 2012, we released the details of our $625 million 2012 capital expenditure program and provided guidance on production and operating costs for 2012. Our 2012 capital program will focus on oil and liquids-rich gas opportunities.

In early February 2012, we commenced the injection of steam at our Lindbergh pilot project.

Three Year Historical Overview

2011

On November 29, 2011, we amended our Credit Facility and extended the term to November 29, 2015.

On November 16, 2011, we completed a bought deal public offering of Common Shares at $10.60 per share for total gross proceeds of approximately $300 million.

On November 3, 2011, we announced a $60 million increase in our 2011 capital program to $610 million.

On August 8, 2011, Marlon McDougall was appointed Chief Operating Officer of the Corporation.

On May 5, 2011, we announced the expansion of our capital program to $550 million for 2011.

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

2010

On November 9, 2010, we released the details of our $400 million 2011 capital expenditure program and provided guidance on production and operating costs for 2011.

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.

Table of Contents

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, the Trust 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.

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 (Swan Hills, Olds, Groundbirch) 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 crude oil 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, 2011, we had 570 permanent employees.

Business Strategy

Our goal is to maximize value creation for Shareholders through reinvesting our cash flow on our near and medium term oil and liquids-rich gas properties while continuing to pay dividends.

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 continue to develop our significant expertise in tight carbonate horizontal well 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 our properties in the greater Swan Hills area, the SAGD project at Lindbergh, with potential for a commercial project providing long term development potential, liquids-rich natural gas in the Olds area, and Montney gas at Groundbirch.

Table of Contents

For 2012, 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.

We have rigorous health, safety and environmental protection policies aimed at ensuring that our operations are conducted in a safe and prudent manner. These policies also encompass our clean-up, abandonment and site reclamation activities.

OPERATIONAL INFORMATION

Principal Producing Properties

The following table summarizes our principal producing properties as of December 31, 2011 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, 2011. The table also contains our average daily production of oil, natural gas and NGL for the year ended December 31, 2011.

Summary of Company Interest

at December 31, 2011(1)

(Forecast Prices and Costs)(2)

Field	P+P Reserves Mboe(5)	Remaining Reserve Life years	P+P Reserve Life Index years	P+P Value Before Tax at 10% DR(4) $MM	2011 Oil Production bblpd	2011 Gas Production MMcfd	2011 NGL Production bblpd	2011 Total Production boepd(5)
Swan Hills Area	92,550	50	11.2	1,818	11,693	18.1	4,953	19,669
Olds Area	36,882	50	11.8	390	517	33.9	2,243	8,409
Groundbirch	28,499	46	31.0	161		18.1		3,010
Weyburn	20,935	47	20.3	449	2,459	0.0		2,459
Subtotal	178,866	50	13.4	2,819	14,669	70.1	7,196	33,548
Remainder(3)	151,645	50	10.7	1,992	13,211	148.5	2,463	40,425
Total	**330,511**	**50**	**12.0**	**4,811**	**27,880**	**218.6**	**9,659**	**73,973**

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 120 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 (6) Mcf of natural gas being equal to one barrel of oil.

Swan Hills Area

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.

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 89.1 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 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.

Also within the Swan Hills area, we have ownership in various other operated and non-operated, unit and non-unit properties in House Mountain, Deer Mountain, Swan Hills, South Swan Hills and Virginia Hills.

In 2012, $255 million is budgeted to be spent on operated light oil and liquids-rich gas plays in the Swan Hills area. We have had significant success utilizing horizontal drilling and multistage acid fracturing technology in this area and have identified significant opportunities from our proof-of-concept initiatives. Our activities at Swan Hills will focus on the development of oil and liquids-rich gas plays in four key areas: Carson Creek, the Judy Creek A and Judy Creek B pools, and Virginia Hills. We expect to drill 37 gross (34 net) wells across the Swan Hills trend. At Carson Creek, we will continue with the development of our reef gas condensate play which has been a key driver of development activity for us since 2009. Production from this play is liquids-rich gas, with approximately 150 to 180 bbls of liquids/MMcf of gas. At Judy Creek, we will continue to exploit numerous development opportunities in the 42 degree API oil, Judy Creek A and B pools, including new drills, re-entries, recompletions, workovers and ongoing miscible flood expansion. The remainder of our activity will focus on expanding our operations within the Swan Hills trend by exploiting development opportunities identified at Virginia Hills, where we currently hold 25 gross (17 net) sections of land.

Olds Area

Our 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 74 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.

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.

The Harmattan gas field, within the Olds area, 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 65 percent in the non-unit lands (operated) and 25 percent in the partner-operated units.

The Olds area is characterized by stacked reservoirs with multi-zone potential. Pengrowth has been exploiting several development opportunities over the past two years in Harmattan, including the development of our liquids-rich Elkton gas play (50 bbls/MMcf) and more recently, the liquids-rich Mannville gas play (90 bbls/MMcf). Approximately $85 million of capital has been allocated to this area in 2012 to drill up to an additional 16 (13 net) wells, of which nine gross wells will target the Elkton and Mannville formations.

Groundbirch

We have an average 90 percent Working Interest in the Groundbirch properties we acquired in September 2010 from Monterey. 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.

The 2011 capital program included further development of the Montney gas resource through four more horizontal drills and completion of four other previously drilled wells. The Montney horizontal wells are all completed with multi-stage fracture stimulation. To-date a total of 14 horizontal Montney wells have been drilled, completed and placed on stream through 100% working interest gas processing facilities. A vertical well which tested gas from the Doig formation was also completed and placed on stream in 2011. The 2012 development plan is to allow facility production to decline as drilling has been deferred to 2013 so as to focus capital on high netback oil and liquids-rich gas opportunities in other areas.

Weyburn

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 CO_2 EOR miscible flood. The field consists of approximately 600 production wells and 330 injection wells.

The 2012 capital program includes purchasing an average of 11.0 MMcfpd of CO_2 for EOR injection and drilling 25 new wells as part of expanding the CO_2 EOR and waterflood patterns.

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, 2011 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, 2011 and the preparation date is January 16, 2012 when the final information was provided. The information in this

Table of Contents

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 Proved Plus Probable Reserves and no attempt was made to evaluate Possible Reserves in our 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, 2011 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 Proved and 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, 2011.

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 COGE 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 after-tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different.

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.

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.

Table of Contents

Reserves Data (Forecast Prices and Costs)

Summary of Oil and Gas Reserves

as of December 31, 2011

(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	67,100	66,944	53,033	16,015	16,011	13,636	19,904	19,875	14,300
Proved Developed Non-Producing	1,902	1,900	1,390	1,774	1,774	1,622	930	926	711
Proved Undeveloped	16,453	16,447	12,770	6,324	6,324	5,459	1,678	1,678	1,238
Total Proved Reserves	**85,455**	**85,291**	**67,194**	**24,112**	**24,108**	**20,716**	**22,512**	**22,479**	**16,249**
Probable Reserves	31,368	31,331	23,924	7,786	7,784	6,397	8,234	8,225	6,034
Total Proved Plus Probable Reserves	**116,823**	**116,622**	**91,117**	**31,898**	**31,892**	**27,113**	**30,746**	**30,704**	**22,283**

	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	486,727	484,643	420,525	23,384	23,100	21,653	188,038	187,454	154,665
Proved Developed Non-Producing	19,496	19,284	15,928	1,242	1,241	1,109	8,062	8,021	6,562
Proved Undeveloped	62,830	62.830	55,895	23,309	23,241	19,977	38,811	38,794	32,112
Total Proved Reserves	**569,053**	**566,757**	**492,348**	**47,935**	**47,582**	**42,739**	**234,910**	**234,268**	**193,340**
Probable Reserves	276,990	276,304	237,435	12,288	12,191	11,039	95,601	95,423	77,766
Total Proved Plus Probable Reserves	**846,043**	**843,061**	**729,783**	**60,223**	**59,773**	**53,778**	**330,511**	**329,691**	**271,107**

Notes:

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

(2) Includes 4,436 Mbbl Proved and 6,348 Mbbl Total Proved Plus Probable Company Interest heavy oil 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 (6) Mcf of natural gas being equal to one barrel of oil.

Table of Contents

Summary of Net Present Value

of Future Net Revenue

as of December 31, 2011

Before and After Income Taxes

(Forecast Prices and Costs)[(1)]

Reserves Category	Before Income Taxes Discounted at (%/Year)					Unit Value Before Income Tax Discounted at 10%/Year[(2) (3)]	
	0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)	$/boe	$/Mcfe
Proved Reserves							
Proved Developed Producing	5,489	4,063	3,242	2,714	2,347	20.96	3.49
Proved Developed Non-Producing	243	160	119	95	79	18.16	3.03
Proved Undeveloped	1,155	649	385	233	138	12.00	2.00
Total Proved Reserves	**6,886**	**4,871**	**3,747**	**3,042**	**2,564**	**19.38**	**3.23**
Probable Reserves	3,300	1,725	1,064	727	531	13.68	2.28
Total Proved Plus Probable Reserves	**10,186**	**6,597**	**4,811**	**3,769**	**3,095**	**17.74**	**2.96**

Reserves Category	After Income Taxes Discounted at (%/Year)[(4)]				
	0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)
Proved Reserves					
Proved Developed Producing	4,909	3,702	2,990	2,523	2,192
Proved Developed Non-Producing	184	130	100	81	67
Proved Undeveloped	863	464	259	143	71
Total Proved Reserves	**5,957**	**4,296**	**3,350**	**2,746**	**2,330**
Probable Reserves	2,524	1,318	810	550	400
Total Proved Plus Probable Reserves	**8,481**	**5,615**	**4,160**	**3,297**	**2,730**

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 (6) 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 (6) 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.

Table of Contents

Additional Information Concerning Future Net Revenue

(undiscounted)

as of December 31, 2011

(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	16,542	3,185	5,358	860	252	6,886	929	5,957
Total Proved Plus Probable Reserves	23,847	4,685	7,425	1,267	284	10,186	1,705	8,481

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.

(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, 2011

(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)	($/Mcfe)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)(2)	2,132	26.51	4.42
	Heavy Oil (including solution gas and other by-products)(2)	495	22.52	3.75
	Natural Gas (including by-products but excluding solution gas from oil wells)(3)	1,073	12.81	2.13
	Non-conventional Oil & Gas Activities	46	6.47	1.08
	Total	**3,747**	**19.38**	**3.23**

Total Proved Plus	Light and Medium Crude Oil (including solution gas and other by-products)(2)	2,704	24.89	4.15
Probable Reserves	Heavy Oil (including solution gas and other by-products)(2)	622	21.62	3.60
	Natural Gas (including by-products but excluding solution gas from oil wells)(3)	1,423	11.41	1.90
	Non-conventional Oil & Gas Activities	62	6.85	1.14
	Total	**4,811**	**17.74**	**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 (6) 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 (6) Mcf of natural gas.

Table of Contents

Reserves Data (Constant Prices and Costs)

Summary of Oil And Gas Reserves

as of December 31, 2011

(Constant Prices and Costs)[1]

Reserves Category	Light and Medium Oil Company Interest (Mbbl)	Light and Medium Oil Gross Interest (Mbbl)	Light and Medium Oil Net Interest (Mbbl)	Heavy Oil[2] Company Interest (Mbbl)	Heavy Oil[2] Gross Interest (Mbbl)	Heavy Oil[2] Net Interest (Mbbl)	Natural Gas Liquids Company Interest (Mbbl)	Natural Gas Liquids Gross Interest (Mbbl)	Natural Gas Liquids Net Interest (Mbbl)
Proved Reserves									
Proved Developed Producing	67,361	67,206	54,378	16,036	16,032	13,788	19,657	19,630	14,137
Proved Developed Non-Producing	1,827	1,826	1,341	1,774	1,774	1,637	822	818	619
Proved Undeveloped	16,474	16,469	12,933	6,326	6,326	5,547	1,648	1,648	1,219
Total Proved Reserves	**85,662**	**85,501**	**68,652**	**24,136**	**24,131**	**20,972**	**22,126**	**22,096**	**15,975**
Probable Reserves	31,779	31,741	25,166	7,784	7,783	6,655	8,149	8,141	6,001
Total Proved Plus Probable Reserves	**117,441**	**117,241**	**93,818**	**31,920**	**31,914**	**27,627**	**30,275**	**30,237**	**21,975**

Reserves Category	Natural Gas Company Interest (MMcf)	Natural Gas Gross Interest (MMcf)	Natural Gas Net Interest (MMcf)	Coal Bed Methane Company Interest (MMcf)	Coal Bed Methane Gross Interest (MMcf)	Coal Bed Methane Net Interest (MMcf)	Total Oil Equivalent Basis[3] Company Interest (Mboe)	Total Oil Equivalent Basis[3] Gross Interest (Mboe)	Total Oil Equivalent Basis[3] Net Interest (Mboe)
Proved Reserves									
Proved Developed Producing	462,984	461,172	404,727	20,025	19,774	18,538	183,555	183,025	152,848
Proved Developed Non-Producing	14,142	14,041	11,769	1,144	1,144	1,023	6,971	6,949	5,729
Proved Undeveloped	57,216	57,216	52,146	15,121	15,092	13,152	36,504	36,493	30,582
Total Proved Reserves	**534,342**	**532,430**	**468,642**	**36,290**	**36,009**	**32,713**	**227,030**	**226,467**	**189,158**
Probable Reserves	264,960	264,319	234,395	13,214	13,125	11,616	94,074	93,906	78,823
Total Proved Plus Probable Reserves	**799,302**	**796,749**	**703,037**	**49,504**	**49,134**	**44,328**	**321,105**	**320,373**	**267,981**

Notes:

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

(2) Includes 4,436 Mbbl Proved and 6,348 Mbbl Total Proved Plus Probable Company Interest heavy oil 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 (6) Mcf of natural gas being equal to one barrel of oil.

Table of Contents

Summary of Net Present Value

of Future Net Revenue

as of December 31, 2011

Before and After Income Taxes

(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	4,750	3,598	2,918	2,472	2,157	19.09	3.18
Proved Developed Non-Producing	192	132	101	82	69	17.65	2.94
Proved Undeveloped	910	516	305	181	102	9.99	1.66
Total Proved Reserves	**5,851**	**4,246**	**3,324**	**2,734**	**2,328**	**17.57**	**2.93**
Probable Reserves	2,375	1,304	827	574	424	10.49	1.75
Total Proved Plus Probable Reserves	**8,226**	**5,550**	**4,151**	**3,309**	**2,751**	**15.49**	**2.58**

Reserves Category	After Income Taxes Discounted At (%/Year)[(4)] 0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)
Proved Reserves					
Proved Developed Producing	4,363	3,358	2,750	2,342	2,050
Proved Developed Non-Producing	147	101	78	63	53
Proved Undeveloped	691	383	217	119	57
Total Proved Reserves	**5,202**	**3,843**	**3,044**	**2,524**	**2,160**
Probable Reserves	1,823	995	627	431	315
Total Proved Plus Probable Reserves	**7,024**	**4,838**	**3,671**	**2,956**	**2,476**

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 (6) 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 (6) 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.

Table of Contents

Additional Information Concerning

Future Net Revenue

(undiscounted)

as of December 31, 2011

(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	13,676	2,553	4,324	754	194	5,851	649	5,502
Total Proved Plus Probable Reserves	18,813	3,538	5,714	1,132	202	8,226	1,202	7,024

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.

(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, 2011

(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)	($/Mcfe)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)(2)	2,045	24.94	4.16
	Heavy Crude Oil (including solution gas and other by-products)(2)	455	20.44	3.41
		803	10.11	1.68

	Natural Gas (including by-products but excluding solution gas from oil wells)[3]			
	Non-conventional Oil & Gas Activities	21	3.83	0.64
	Total	**3,324**	**17.57**	**2.93**
Total Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)[2]	2,566	23.00	3.83
	Heavy Crude Oil (including solution gas and other by-products)[2]	569	19.42	3.24
	Natural Gas (including by-products but excluding solution gas from oil wells)[3]	989	8.26	1.38
	Non-conventional Oil & Gas Activities	27	3.60	0.60
	Total	**4,151**	**15.49**	**2.58**

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 (6) 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 (6) Mcf of natural gas.

Table of Contents

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, 2012 price forecast as referred to in the GLJ Report.

	Oil				Natural Gas	Natural Gas Liquids[1]				
Year	**WTI Cushing Oklahoma (US$/bbl)**	**Edmonton Par Price 40^{0}API (Cdn$/bbl)**	**Cromer Medium 29.3^{0}API (Cdn$/bbl)**	**Hardisty Heavy 12^0 API (Cdn$/bbl)**	**AECO Gas Price (Cdn$/MMBtu)**	**Propane (Cdn$/bbl)**	**Butane (Cdn$/bbl)**	**Pentanes Plus (Cdn$/bbl)**	**Inflation Rates[2] (%/Year)**	**Exchange Rate[3] (US$/Cdn$)**
2011[4]	94.83	95.15	87.57	67.03	3.68	53.47	74.24	103.75		
2012	97.00	97.96	90.12	72.37	3.49	58.78	76.41	107.76	2.0	0.98
2013	100.00	101.02	92.94	73.60	4.13	60.61	78.80	108.09	2.0	0.98
2014	100.00	101.02	91.93	74.51	4.59	60.61	78.80	105.06	2.0	0.98
2015	100.00	101.02	91.93	74.51	5.05	60.61	78.80	105.06	2.0	0.98
2016	100.00	101.02	91.93	74.51	5.51	60.61	78.80	105.06	2.0	0.98
2017	100.00	101.02	91.93	74.51	5.97	60.61	78.80	105.06	2.0	0.98
2018	101.35	102.40	93.18	75.54	6.21	61.44	79.87	106.49	2.0	0.98
2019	103.38	104.47	95.07	77.09	6.33	62.68	81.49	108.65	2.0	0.98
2020	105.45	106.58	96.99	78.67	6.46	63.95	83.13	110.84	2.0	0.98
2021	107.56	108.73	98.95	80.28	6.58	65.24	84.81	113.08	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 average historical prices for 2011.

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 2011 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$/bbl)**	**Edmonton Par Price 40^0 API (Cdn$bbl)**	**Cromer Medium 29.3^0 API (Cdn$bbl)**	**Hardisty Heavy 12^0 API (Cdn$bbl)**	**AECO Gas Price (Cdn$MMBtu)**	**Propane (Cdn$bbl)**	**Butane (Cdn$bbl)**	**Pentanes Plus (Cdn$bbl)**	**Inflation Rate (%/Year)**	**Exchange Rat e[2] (USCdn)**

2012 and thereafter	95.99	97.03	89.66	69.22	3.78	54.02	74.21	105.50	0.0%	1.0166

Notes:

(1) FOB Edmonton.

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

Table of Contents

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, 2011, 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, 2010	81,077	29,024	110,101	15,232	11,233	26,465	21,216	8,216	29,432
Technical Revisions	5,281	(1,017)	4,264	3,260	(986)	2,274	2,300	(452)	1,848
Discoveries									
Extensions	4,920	2,755	7,674	4,459	(4,196)	263	2,253	347	2,600
Infill Drilling	1,238	453	1,691	676	71	747	209	114	323
Improved Recovery	646	139	786	2,827	1,662	4,489	45	16	62
Acquisitions	84	24	107				9	3	12
Dispositions	(152)	(47)	(200)				(38)	(18)	(57)
Economic Factors									
Production	(7,803)		(7,803)	(2,345)		(2,345)	(3,515)		(3,515)
December 31, 2011	**85,291**	**31,331**	**116,622**	**24,108**	**7,784**	**31,892**	**22,479**	**8,225**	**30,704**

	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, 2010	564,062	279,489	843,551	52,680	12,866	65,547	220,316	97,198	317,514
Technical Revisions	29,357	(22,039)	7,317	(1,496)	(675)	(2,172)	15,484	(6,239)	9,245
Discoveries									
Extensions	45,737	17,771	63,508				19,254	1,868	21,122
Infill Drilling	3,129	1,185	4,315				2,645	835	3,480
Improved Recovery	202	210	413				3,552	1,853	5,405
Acquisitions	101	33	133				110	31	141
Dispositions	(431)	(345)	(776)				(263)	(123)	(386)
Economic Factors									
Production	(75,400)		(75,400)	(3,602)		(3,602)	(26,830)		(26,830)
December 31, 2011	**566,757**	**276,304**	**843,061**	**47,582**	**12,191**	**59,773**	**234,268**	**95,423**	**329,691**

Note:

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six (6) Mcf of natural gas being equal to one barrel of oil.

Table of Contents

At December 31 2011, Company Interest Total Proved Plus Probable Reserves at forecast prices and costs were 330.5 MMboe as compared to 318.4 MMboe reported at year end 2010. The following additional GLJ reserves reconciliation is presented for year end December 31, 2011.

Company Interest Reserves Reconciliation

on Total Oil Equivalent Basis

(Forecast Prices and Costs)

	Proved Developed Producing Reserves (Mboe)(1)	Total Proved Reserves (Mboe)(1)	Total Proved Plus Probable Reserve (Mboe)(1)
December 31, 2010	183,664	221,028	318,429
Technical Revisions	16,430	15,587	9,322
Discoveries			
Extensions	11,193	19,258	21,128
Infill Drilling	1,383	2,645	3,480
Improved Recovery	2,536	3,553	5,405
Acquisitions	100	110	141
Dispositions	(269)	(269)	(394)
Economic Factors			
Production	(27,000)	(27,000)	(27,000)
December 31, 2011	**188,038**	**234,910**	**330,511**

Note:

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six (6) 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 152 percent and 146 percent of 2011 production for Proved Reserves and Total Proved Plus Probable Reserves, respectively. Based on all changes, including acquisitions and dispositions, reserve replacement was 151 percent and 145 percent for Proved Reserves and Proved Plus Probable Reserves, respectively.

New reserve additions for development activity during 2011 amounted to 30.0 MMboe of Total Proved Plus Probable Reserves. Most significant were drilling extensions in our resource plays at Groundbirch, Judy Creek and Harmattan, and polymer flood development at East Bodo. 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 Groundbirch, Judy Creek, Carson Creek and Harmattan and improved recovery at East Bodo.

Approximately 34 percent of the Total Proved Plus Probable Reserve additions were light oil, 18 percent were heavy oil, 10 percent were NGL and 38 percent were natural gas.

Technical revisions due to improved performance resulted in a net increase of 9.3 MMboe of Total Proved Plus Probable Reserves primarily in Harmattan, Quirk Creek, Jenner and Carson Creek, and includes a negative performance revision of 4.9 MMboe at Groundbirch.

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 Undeveloped Reserves 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 for staged developments such as the Judy Creek, Swan Hills and Weyburn miscible flood projects, and the Lindbergh oil sands development. Other longer term capital expenditures are for gas development most of which has been deferred with capital being allocated instead to higher-impact oil opportunities.

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	17,029	17,029	1,676	1,676	48,311	48,311	10,372	10,372	1,120	1,120	29,606	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
2011	2,891	16,447	5,599	6,324	18,332	62,830		23,241	1,027	1,678	12,572	38,794

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	12,372	12,372	7,857	7,857	68,822	68,822	7,948	7,948	3,478	3,478	36,502	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
2011	2,185	12,015	1,767	4,193	44,814	139,429		6,077	1,210	2,535	12,630	42,994

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 (6) Mcf of natural gas being equal to one barrel of oil.

Proved Undeveloped Reserves

Our Proved Undeveloped Reserves comprise approximately 17 percent of Company Interest total Proved Reserves on a barrel of oil equivalency basis. Company Interest Proved Undeveloped Reserves of 38.8 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 16 percent of our Proved Undeveloped Reserves. Drilling is forecast by GLJ to occur over the next two years to develop these reserves. At Judy Creek, drilling and miscible flood development is forecast to continue until 2015 and accounts for another 14 percent of Company Interest Proved Undeveloped Reserves. Similarly, in the Swan Hills unit miscible flood expansion, as well as some infill drilling, comprises 11 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 2030. In the Weyburn Unit, the Proved Undeveloped Reserves amount to nine percent of the total, and reflect the capital allocated to infill drilling, waterflood realignment and CO_2 miscible flood expansion, forecast to continue until 2018. Our CBM development requires further drilling at Twining, Huxley and Fenn Big Valley. Because of the extensive land holdings and slower pace of development, this is forecast to occur over the next five years and represents another nine percent of the Proved Undeveloped Reserves. Approximately seven percent of Pengrowth s Company Interest Proved Undeveloped Reserves are assigned to the heavy oil polymer flood development in East Bodo that is forecast to occur over the next four years. At Harmattan, drilling extensions and infill drilling scheduled over the next three years account for about six percent of 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 43.0 MMboe and represent about 13 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 (37 percent), Weyburn Unit (eight percent), Judy Creek (seven percent), Swan Hills Unit (six percent), East Bodo (four percent) and Lindbergh (four percent).

Table of Contents

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.

Reserve Category	2012 ($MM)	2013 ($MM)	2014 ($MM)	2015 ($MM)	2016 ($MM)	Remainder ($MM)	Undiscounted ($MM)	Total Discounted at 10% ($MM)
Proved Reserves (Constant Prices and Costs)	246	194	74	57	24	159	754	577
Proved Reserves (Forecast Prices and Costs)	247	208	90	63	32	220	860	631
Proved & Probable Reserves (Forecast Prices and Costs)	300	335	172	113	58	289	1,267	926

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 $625 million capital expenditure program for 2012 to fund our land acquisition, development and exploration activities, including expenditures at our Lindbergh oil sands SAGD project.

Finding, Development and Acquisition Costs

Finding and Development Costs

During 2011, we spent $603.4 million, net of Alberta drilling royalty credits, on development and optimization activities, which added 41.0 MMboe of Proved Reserves and 39.3 MMboe of Total Proved Plus Probable Reserves including revisions. The development and optimization activities exclude $5.7 million in expenditures mainly for information technology projects in the Calgary office. The largest reserve additions were for drilling and improved recovery projects at Groundbirch, East Bodo, Swan Hills and Olds.

In total, we participated in drilling 241 gross wells (123 net wells) with a 99 percent success rate.

Extensive development occurred in the Pengrowth-operated Swan Hills Beaverhill Lake trend during 2011. In addition to ongoing miscible flood development and waterflood optimization, we also drilled a total of 27 horizontal oil wells at Judy Creek, primarily in the tighter platform and reef margin. We also drilled 11 liquids-rich gas wells and two oil wells at Carson Creek and three wells in Deer Mountain. Multi-stage fracture treatments were used in the completion of these wells.

Drilling and miscible flood development also occurred in the partner-operated properties where we participated in 14 oil wells at House Mountain and five each in the Swan Hills and South Swan Hills units.

We drilled a total of 34 wells, including 26 producers, at East Bodo where a polymer flood is being implemented to increase heavy oil recovery in the Lloydminster formation. Similar drilling programs are planned over the next few years.

At Lindbergh, we drilled 14 stratigraphic test/observation wells during 2011 to better understand the reservoir and delineate the pool. In addition, two SAGD wells pairs were drilled in the pilot area where steam injection commenced in early February 2012.

In the Olds area, we drilled, or participated in the drilling of, nine successful horizontal wells resulting in three Cardium oil wells, one Viking oil well, three Elkton gas wells and two Mannville gas wells.

We continue to develop Montney gas at Groundbirch since the acquisition of Monterey in September 2010. During 2011, we drilled and completed four new horizontal wells and completed four others previously drilled. We now have a total of 15 producing wells since coming on stream in December 2010.

Further development and optimization occurred in the CO_2 miscible flood and waterflood areas of the Weyburn Unit in southeast Saskatchewan. During 2011, 37 wells were drilled in the unit, consisting of 24 water and CO_2 injection wells, 11 producers and two observation wells.

Various other drilling programs and optimization work were conducted during 2011 to test new concepts, increase production and maximize recoveries.

Table of Contents

Acquisitions and Divestitures

During 2011, minor asset acquisitions were made at Carson Creek, Deer Mountain, Judy Creek and Virginia Hills to increase interests and acquire undrilled acreage in existing core areas. In aggregate we spent $8.6 million and acquired 0.1 MMboe of Total proved Plus Probable Reserves and 7.1 net sections of undrilled lands.

Total proceeds from minor dispositions of small, isolated properties and undeveloped acreage during 2011 were $16.9 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)

Proved Reserves	**2011 Proved**	**2010 Proved**	**2009 Proved**	**2009-2011 Weighted Average Proved**
Costs Excluding Future Development Capital				
Exploration and Development Capital Expenditures - $M	603,394	329,470	202,200	1,135,064
Exploration and Development Reserve Additions including Revisions - Mboe	41,042	20,505	11,291	72,838
Finding and Development Cost - $/boe	14.70	16.07	17.91	15.58
Net Acquisition Capital - $M	(8,307)	400,600	(6,230)	386,063
Net Acquisition Reserve Additions - Mboe	(160)	11,232	(937)	10,135
Net Acquisition Cost - $/boe	52.06	35.67	6.65	38.09
Total Capital Expenditures including Net Acquisitions - $M	595,087	730,070	195,970	1,521,127
Reserve Additions including Net Acquisitions - Mboe	40,883	31,737	10,354	82,973
Finding Development and Acquisition Cost - $/boe	14.56	23.00	18.93	18.33
Costs Including Future Development Capital				
Exploration and Development Capital Expenditures - $M	603,394	329,470	202,200	1,135,064
Exploration and Development Change in FDC - $M	257,000	32,000	(42,800)	246,200
Exploration and Development Capital including Change in FDC - $M	860,394	361,470	159,400	1,381,264
Exploration and Development Reserve Additions including Revisions - Mboe	41,042	20,505	11,291	72,838
Finding and Development Cost - $/boe	20.96	17.63	14.12	18.96

Net Acquisition Capital - $M	(8,307)	400,600	(6,230)	386,063
Net Acquisition FDC - $M	0	34,000	800	34,800
Net Acquisition Capital including FDC - $M	(8,307)	434,600	(5,430)	420,863
Net Acquisition Reserve Additions - Mboe	(160)	11,232	(937)	10,135
Net Acquisition Cost - $/boe	52.06	38.69	5.80	41.53
Total Capital Expenditures including Net Acquisitions - $M	595,087	730,070	195,970	1,521,127
Total Change in FDC - $M	257,000	66,000	(42,000)	281,000
Total Capital including Change in FDC - $M	852,087	796,070	153,970	1,802,127
Reserve Additions including Net Acquisitions - Mboe	40,883	31,737	10,354	82,973
Finding Development and Acquisition Cost including FDC - $/boe	20.84	25.08	14.87	21.72

Table of Contents

Total Proved Plus Probable Reserves	2011 Proved plus Probable	2010 Proved plus Probable	2009 Proved plus Probable	2009-2011 Weighted Average Proved plus Probable
Costs Excluding Future Development Capital				
Exploration and Development Capital Expenditures - $M	603,394	329,470	202,200	1,135,064
Exploration and Development Reserve Additions including Revisions - Mboe	39,335	27,127	2,577	69,039
Finding and Development Cost - $/boe	15.34	12.15	78.46	16.44
Net Acquisition Capital - $M	(8,307)	400,600	(6,230)	386,063
Net Acquisition Reserve Additions - Mboe	(253)	22,832	(1,283)	21,296
Net Acquisition Cost - $/boe	32.85	17.55	4.86	18.13
Total Capital Expenditures including Net Acquisitions - $M	595,087	730,070	195,970	1,521,127
Reserve Additions including Net Acquisitions - Mboe	39,082	49,959	1,294	90,335
Finding Development and Acquisition Cost - $/boe	15.23	14.61	151.45	16.84
Costs Including Future Development Capital				
Exploration and Development Capital Expenditures - $M	603,394	329,470	202,200	1,135,064
Exploration and Development Change in FDC - $M	188,000	86,000	(122,800)	151,200
Exploration and Development Capital including Change in FDC -$M	791,394	415,470	79,400	1,286,264
Exploration and Development Reserve Additions including Revisions - Mboe	39,335	27,127	2,577	69,039
Finding and Development Cost - $/boe	20.12	15.32	30.81	18.63
Net Acquisition Capital - $M	(8,307)	400,600	(6,230)	386,063
Net Acquisition FDC - $M	0	106,000	800	106,800
Net Acquisition Capital including FDC - $M	(8,307)	506,600	(5,430)	492,863
Net Acquisition Reserve Additions - Mboe	(253)	22,832	(1,283)	21,296
Net Acquisition Cost - $/boe	32.85	22.19	4.23	23.14
Total Capital Expenditures including Net Acquisitions - $M	595,087	730,070	195,970	1,521,127
Total Change in FDC - $M	188,000	192,000	(122,000)	258,000
Total Capital including Change in FDC - $M	783,087	922,070	73,970	1,779,127
Reserve Additions including Net Acquisitions - Mboe	39,082	49,959	1,294	90,335
Finding Development and Acquisition Cost including FDC - $/boe	20.04	18.46	57.16	19.69

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

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.

	2011	2010	2009	2009-2011 Weighted Average
Recycle Ratio	1.4	1.8	0.9	1.5
Operating Netback, $/boe[(1)]	28.45	26.92	26.07	27.12
P+P F&D, $/boe[(2)]	20.12	15.32	30.81	18.63

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.

Table of Contents

Reserve Life Index (RLI)

The reserve life index provides a comparative measure of the longevity of the resources. We calculate the RLI by dividing 2011 Company Interest year end reserves by GLJ s 2012 forecasted production.

	Proved Producing Reserves	Total Proved Reserves	Total Proved Plus Probable Reserves
RLI, years	7.6	9.0	12.0
Reserves, Mboe[(1)(2)]	188,038	234,810	330,511
2012 Forecast Production, boe/d[(1)]	67,396	71,879	75,298

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.

	2011	2010	2009	Weighted Average/ Total 2009-2011
Without Net Acquisitions Proven Plus Probable Replacement	146%	99%	9%	83%
P+P Drill Adds plus Revisions, MMboe[(1)]	39.3	27.1	2.6	69.0
With Net Acquisitions Proven Plus Probable Replacement	145%	183%	4%	109%
P+P Adds, Revisions plus net Acquisitions, MMboe[(1)]	39.1	50.0	1.3	90.4
Without Net Acquisitions Total Proved Replacement	152%	75%	39%	87%
Total Proved Drill Adds plus Revisions, MMBoe[(1)]	41.0	20.5	11.3	72.8
With Net Acquisitions Total Proved Replacement	151%	116%	36%	100%
Total Proved Adds, Revisions plus net Acquisitions, MMboe[(1)]	40.9	31.7	10.4	83.0
Current Year Production, MMboe[(1)]	27.0	27.3	29.0	83.3

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 (6) Mcf of natural gas being equal to one barrel of oil.

Other Oil and Gas Information

Oil and Gas Wells

As at December 31, 2011, we had an interest in 8,103 gross (4,099 net) producing oil and natural gas wells and 2,562 gross (1,423 net) non-producing oil and natural gas wells.

	Producing		**Non-Producing**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Crude Oil Wells						
Alberta	1,743	1,153	833	503	2,576	1,656
British Columbia	91	58	143	94	234	152
Saskatchewan	875	179	538	204	1,413	383
Nova Scotia						
Natural Gas Wells						
Alberta	5,139	2,553	563	296	5,702	2,849
British Columbia	196	118	114	70	310	188
Saskatchewan	40	36	39	30	79	66
Nova Scotia	19	2			19	2
Other(1)						
Alberta			261	187	261	187
British Columbia			42	33	42	33
Saskatchewan			29	6	29	6
Total	8,103	4,099	2,562	1,423	10,665	5,522

Note:

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

Table of Contents

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, 2011 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.

When determining gross and net acreage for two or more leases covering the same lands but different rights, the acreage is reported for each lease. Where there are multiple discontinuous rights in a single lease, the acreage is reported only once.

Unproved Properties

as at December 31, 2011

Location	**Gross Acres**	**Net Acres**	**Maximum Net Acres That May Expire During 2012**
Alberta	814,896	572,907	63,188
British Columbia	401,628	220,078	106,449
Ontario	4,776		
Saskatchewan	60,844	40,657	7,550
Nova Scotia	200,650	15,957	
Total	**1,482,794**	**849,599**	**177,187**

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 50 kilometres south of Bonnyville. We have a 100% Working Interest in the Lindbergh oil sands leases, located in the Cold Lake oil sands district in north-eastern Alberta and covering 20,800 net acres (32.5 sections). There are a total of 106 existing wells that have been used in the geological evaluation. The Corporation has drilled and evaluated 34 core holes since acquiring the property in 2004. Additionally, 36 square kilometres of three dimensional seismic along with 55 kilometres of two dimensional seismic, has been shot and evaluated.

The main bitumen resource at Lindbergh is located within the Lloydminster Formation of the Mannville Group, at an approximate depth of 500 metres. Oil quality averages 11° API. The average exploitable reservoir pay thickness is 18 metres in the project area. There appear to be limited, if any, top water or top gas thief zones within the Lloydminster Formation. A competent caprock is provided by the General Petroleum shale, which is believed to be pervasive and consistent throughout the area.

We own a central processing facility and pad site and have drilled and completed two SAGD well pairs in December 2011. The wells were drilled from a single pad with each having an effective horizontal well length of 840 metres within the bitumen-bearing Lloydminster formation.

Both well pairs encountered high quality reservoir throughout, and most notably, the absence of lean zones and shale barriers in any of the well bores. All horizontal sections were drilled to design length, with none of the well bores exiting the edge of the reservoir target area.

We began injecting steam at the Lindbergh pilot in early February 2012. Pending favourable pilot results, the first phase of the Lindbergh Commercial Project will have a maximum design capacity of 12,500 bbl/d of bitumen (including the pilot area) with an expected project life of 30 years. Over the life of the Lindbergh project, there are expected to be approximately 60-65 well pairs drilled from approximately eight or nine well pads within the project area, recovering in excess of 107 MMbbls of bitumen. The production life for each individual well pair is estimated to be approximately 10 12 years. As the individual well pair production declines, additional well pairs will be drilled throughout the Lindbergh project area to maintain production. Future expansion of the Lindbergh Commercial Project will increase the production capacity to 30,000 bbl/d.

The Corporation submitted an application for a 12,500 bblpd Commercial Project to the ERCB and Alberta Environment on December 23, 2011. Regulatory approval of this application is expected in the second quarter of 2013, with construction able to commence shortly thereafter.

Proved, Probable and Possible Reserves have been assigned to the pilot project. In addition, there are economic Contingent Resources for the area beyond the pilot. GLJ has updated the evaluation of the reserves and Contingent Resources for Lindbergh as of December 31, 2011. The evaluation was limited to portions of the reservoir amenable to 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 economic 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.

Table of Contents

Proved and Probable Reserves have been assigned within the region of the proposed pilot development area. Proved plus Probable plus Possible Reserves have been assigned to this same pilot area as well as a previously delineated region offsetting the pilot. The Proved and Probable Reserves attributed to the Lindbergh property have been included in the reserves disclosed under - *Statement of Oil and Gas Reserves and Reserves Data* .

Lindbergh Oil Sands Project

Proved, Proved plus Probable and Proved plus Probable plus Possible Reserves

as of December 31, 2011

(Forecast Prices and Costs)

	Proved Reserves	Proved plus Probable Reserves	Proved plus Probable plus Possible Reserves
Gross Reserves (MMbbl)	4.4	6.3	18.4

Contingent Resources have been assigned to the remaining areas of the reservoir within the property that meet certain minimum criteria. In 2011, we drilled 14 stratigraphic test/observation wells. As a result of increasing the project area, delineating the pool further and mapping a larger area which can potentially be developed, GLJ has increased their estimate of exploitable BIIP and economic Contingent Resources from 2010 year end as shown below. Contingent Resources have been assigned on the basis of a technically feasible SAGD recovery project having been defined. However, there is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.

A significant portion of these resource volumes are classified as a resource rather than a reserve because they are contingent upon favorable pilot performance. The remainder are contingent upon favourable pilot performance, ongoing reservoir studies, delineation drilling and facility design and preparation of firm development plans, regulatory application approval and corporate approvals relating to commercial development. We anticipate these contingencies will be satisfied during 2012 which should allow us to book a significant portion of the Contingent Resources as Proved and Probable Reserves by or before year-end.

	December 31, 2011		December 31, 2010	
	Exploitable BIIP(1) (Gross MMbbl)	Contingent Resources(2) (Gross MMbbl)	Exploitable BIIP(1) (Gross MMbbl)	Contingent Resources(2) (Gross MMbbl)
Low Estimate(3)	591	193	396	149
Best Estimate(4)	783	296	439	193
High Estimate(5)	1,013	476	510	258

Notes:

(1) Exploitable BIIP is that portion of bitumen initially in place which is amenable to SAGD development.

(2) 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.

(3)

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.

(4) 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.

(5) 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. 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 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.

Table of Contents

The tables below summarize the estimated volumes of Company Interest reserves and economic 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

as of December 31, 2011

(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)	31.5	67.6	168.9	196.9
NGL (MMbbl)	0.1	0.1	0.4	0.4
Total (MMboe)(1)	5.3	11.4	28.5	33.2

Note:

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six (6) 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. GLJ s estimate of economic Contingent Resources has decreased compared to 2010 year end as shown below. The decrease from last year is largely due to steeper sustained initial declines in the producing wells which result in lower recoveries. Also, certain areas now have reserves assigned based on further development thus reducing the Contingent Resources in those areas of the pool.

Contingent Resources are assigned on the basis of a technically feasible recovery project having been defined. These Contingent Resources are expected to be economic to develop. The reclassification of these Contingent Resources as reserves is contingent upon performance of existing wells and preparation and corporate approval of a development plan. However, there is no certainty that it will be commercially viable to produce any portion of the Contingent Resource.

	December 31, 2011 Contingent Resources(1) (Gross)	December 31, 2010 Contingent Resources(1) (Gross)
Low Estimate(2)		
Gas, MMcf	155.3	249.9
NGL, MMbbl	0.3	0.5
Total, MMboe(5)	26.2	42.1
Best Estimate(3)		
Gas, MMcf	271.5	424.4
NGL, MMbbl	0.6	0.9
Total, MMboe(5)	45.8	71.6

High Estimate[4]		
Gas, MMcf	488.6	630.7
NGL,s MMbbl	1.0	1.3
Total, MMboe[5]	82.5	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) 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) 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) 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 (6) 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. The size of the resource estimate could be positively impacted, potentially in a material amount, if additional development 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 development 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 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 note 18 of our annual audited consolidated financial statements and related management s discussion and analysis for the year ended December 31, 2011, 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, which are inclusive of those costs estimated by GLJ, to be approximately $108 million as at December 31, 2011, based on a total future liability (inflated at 1.5 percent per annum) of approximately $1,845 million. These costs are anticipated to be paid over 65 years with the majority of the costs incurred in the last 20 years and applies to 7,848 net wells (14,729 gross wells).

The following table summarizes our total current asset retirement obligations as at December 31, 2011:

Asset Retirement Obligations

	2012 ($MM)	2013 ($MM)	2014 ($MM)	Remainder ($MM)	Total ($MM)
Total Abandonment, Reclamation, Remediation & Dismantling	6.0	5.7	5.8	1,827.7	1,845.2
Discounted at ten percent	5.7	5.0	4.6	92.5	107.8

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 $234 million ($85 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 $234 million, or $85 million when discounted at ten percent, is excluded elsewhere.

Tax Horizon

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 having to pay corporate income tax until at least 2015.

Table of Contents

Costs Incurred

The following table outlines property acquisition, exploration and development costs that we incurred during the financial year ended December 31, 2011. These costs include only those costs which are cash or cash equivalent.

Nature of Cost	Amount ($MM)
Acquisition Costs[(1)]	
Proved	3.1
Unproved	5.5
Exploration Costs	88.2
Development Costs	515.2
Total	**612.0**

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, 2011 financial statements, and cash paid for other properties acquired.

Exploration and Development Activities

The following table summarizes the number of wells drilled during the financial year ended December 31, 2011.

	Development		Exploration		Total	
Wells	Gross	Net	Gross	Net	Gross	Net
Gas	26	18.3	1	0.7	27	19.0
Oil	153	69.4	4	4.0	157	73.4
Service	43	17.8			43	17.8
Stratigraphic Test	11	11.0			11	11.0
Dry	3	1.4			3	1.4
Total	**236**	**117.9**	**5**	**4.7**	**241**	**122.6**

Production Estimates

The following tables summarize the 2012 average daily volume of gross production estimated by GLJ for all properties held on December 31, 2011 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 2012 Company Interest production to be between 74,500 and 76,500 boepd.

	2012 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)	22,329	23,624	22,329	23,624
Heavy Crude Oil (bblpd)	7,144	7,444	7,144	7,444
Natural Gas (Mcfpd)	196,635	203,380	196,663	203,436
Natural Gas Liquids (bblpd)	9,388	10,075	9,388	10,075

Total (boepd)	**71,633**	**75,039**	**71,638**	**75,049**

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, 2011	**June 30, 2011**	**Sept 30, 2011**	**Dec 31, 2011**	**Dec 31, 2011**
Barrels of Oil Equivalent [1]					
Average Daily Oil Production[2] (boepd)	73,634	70,958	74,568	76,691	73,973
Sales price (after commodity risk management) ($/boe)	51.15	54.41	52.68	54.28	53.13
Other production income ($/boe)	0.29	0.83	0.81	0.89	0.71
Oil & gas sales ($/boe)	51.44	55.24	53.49	55.17	53.84
Royalties ($/boe)	(9.11)	(11.18)	(10.65)	(10.25)	(10.29)
Operating expenses ($/boe)	(13.81)	(14.14)	(14.51)	(14.13)	(14.15)
Transportation costs ($/boe)	(0.88)	(0.95)	(1.18)	(0.80)	(0.95)
Operating netback ($/boe)	27.64	28.97	27.15	29.99	28.45
Light Crude					
Average Daily Oil Production [2] (bblpd)	21,066	20,641	21,163	22,935	21,455
Sales price (after commodity risk management) ($/bbl)	83.21	92.82	91.95	91.58	89.94
Other production income ($/bbl)	0.59	0.80	0.94	0.91	0.81

Table of Contents

	QUARTER ENDED				YEAR ENDED
	Mar 31, 2011	June 30, 2011	Sept 30, 2011	Dec 31, 2011	Dec 31, 2011
Oil & gas sales ($/bbl)	83.80	93.62	92.89	92.49	90.75
Royalties ($/bbl)	(17.82)	(21.83)	(20.46)	(21.29)	(20.37)
Operating expenses ($/bbl)	(16.29)	(15.62)	(17.78)	(15.40)	(16.26)
Transportation costs ($/bbl)	(2.14)	(2.32)	(3.25)	(1.75)	(2.36)
Operating netback ($/bbl)	47.55	53.85	51.40	54.05	51.76
Heavy Oil					
Average Daily Oil Production [2] (bblpd)	6,639	6,225	6,387	6,448	6,425
Oil & gas sales ($/bbl)	60.02	74.74	62.36	76.13	68.24
Royalties ($/bbl)	(9.07)	(18.54)	(14.23)	(13.65)	(13.81)
Operating expenses ($/bbl)	(12.73)	(15.70)	(15.54)	(13.91)	(14.45)
Operating netback ($/bbl)	38.22	40.50	32.59	48.57	39.98
Natural Gas[3]					
Average Daily Natural Gas Production [2] (Mcfpd)	220,517	213,342	219,552	220,977	218,601
Sales price (after commodity risk management) ($/Mcf)	4.35	4.18	4.05	3.77	4.08
Other production income ($/Mcf)	0.04	0.19	0.17	0.21	0.16
Oil & gas sales ($/Mcf)	4.39	4.37	4.22	3.98	4.24
Royalties ($/Mcf)	(0.41)	(0.35)	(0.31)	(0.26)	(0.33)
Operating expenses ($/Mcf)	(2.08)	(2.08)	(1.98)	(2.31)	(2.11)
Transportation costs ($/Mcf)	(0.09)	(0.09)	(0.09)	(0.09)	(0.09)
Operating netback ($/Mcf)	1.81	1.85	1.84	1.32	1.71
NGLs					
Average Daily Oil Production [2] (bblpd)	9,176	8,535	10,426	10,478	9,659
Oil & gas sales ($/bbl)	71.40	68.95	66.58	70.54	69.31
Royalties ($/bbl)	(15.87)	(17.95)	(19.42)	(14.51)	(16.92)
Operating expenses ($/bbl)	(13.43)	(15.90)	(17.03)	(12.34)	(14.65)
Transportation costs ($/bbl				(0.20)	(0.05)
Operating netback ($/bbl)	42.10	35.10	30.13	43.49	37.69

Note:

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six (6) Mcf of natural gas being equal to one boe.

(2) Before the deductions of royalties.

(3) Includes CBM production.

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 on or about the 22nd 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. A list of all anticipated dividend record dates for 2012 can be found at www.pengrowth.com/investors/dividends/.

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 dividends declared by the Corporation in 2011 and distributions declared by the Trust in respect of 2009 and 2010 on the outstanding Common Shares and Trust Units, respectively, for the periods indicated, with each amount being paid in the following month:

Month	**2011 ($/share)**	**2010 ($/share)**	**2009 ($/share)**
January	0.07	0.07	0.10
February	0.07	0.07	0.10
March	0.07	0.07	0.10
April	0.07	0.07	0.10
May	0.07	0.07	0.10
June	0.07	0.07	0.10
July	0.07	0.07	0.10
August	0.07	0.07	0.10
September	0.07	0.07	0.07
October	0.07	0.07	0.07
November	0.07	0.07	0.07
December	0.07	0.07	0.07
Total	**0.84**	**0.84**	**1.08**

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.

Table of Contents

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, 2011, our legal stated capital was approximately $1.346 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: Income taxes; Interest expense; All provisions for federal, provincial or other income and capital taxes; Depreciation, depletion and amortization expense; and 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.

Table of Contents

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 and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia, Saskatchewan and 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 legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing

Oil

The producers of oil are able 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, availability and cost of transportation capacity to various markets, 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.

Table of Contents

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta NIT (Nova Inventory Transfer) 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.

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.

The North American Free Trade Agreement

The North American Free Trade Agreement (NAFTA) among the governments of Canada, the United States and Mexico became effective on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner s interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

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

Alberta

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

On October 25, 2007, the Government of Alberta released a report entitled The New Royalty Framework (**NRF**) containing proposals which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. Changes in Alberta s royalty system, in effect after December 31, 2010, is known as the Alberta Royalty Framework (the **ARF**).

Under the ARF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the ARF was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/m^3 compared to the previous royalty curve.

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

Oil sands projects are also subject to the ARF. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 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. 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 or the ARF.

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 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 spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well s life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the ARF. 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. One aspect of the program was a drilling royalty credit program which provided up to a $200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. Another aspect of the program was a new well royalty program which provided for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated volume cap was reached. The *New Well Royalty Regulation*, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011.

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

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

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

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 77 percent of our Company Interest production forecast for 2012 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, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 (old oil), between October 31, 1975 and June 1, 1998 (new oil), or after June 1, 1998 (third-tier oil). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

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

Summer Royalty Credit Program providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

Deep Royalty Credit Program providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres;

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 with a spud date after November 30, 2003;

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 reductions 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 reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 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; and

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

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

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (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 2009, 2010 and 2011, the Government of British Columbia awarded $120 million in royalty credits to 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. 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. 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 2012 is in the Province of British Columbia on Crown lands.

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is 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.

Table of Contents

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the 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* replacing the existing *Freehold Oil and Gas Production Tax Act* and with the intention 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 legislation, although several regulations remain in force under the previous legislation.

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 Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013 providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells.

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;

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; and

Royalty/Tax Regime for High Water-Cut Oil Wells granting third tier oil royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities; and

Table of Contents

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.

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

Approximately seven percent of our Company Interest production forecast for 2012 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 2012 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.

Alberta also has a policy of shallow rights reversion which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences 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. The order in which these agreements will receive reversion notices will depend on their vintage and location, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and will revisit the decision in spring 2012.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the **ALUF**). The ALUF sets out an approach to manage public and private land use and natural resource development in a

Table of Contents

manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The *Alberta Land Stewardship Act* (the **ALSA**) was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 29, 2011 the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the **Revised LARP**) updating its prior draft of April 5, 2011 (the **Draft LARP**). The Revised LARP, while establishing several conservation areas of the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas. However, references to the cancellation of existing tenures have been removed from the Revised LARP and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

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 although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol.

On April 26, 2007, the Government of Canada released Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution (the **Action Plan**) which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions was released on March 10, 2008 (the **Updated Action Plan**). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between Existing Facilities and New Facilities . For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. New Facilities are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility s physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage (**CCS**) technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boepd/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:

(a) Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG 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.

(b) 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.

(c) Under the Updated Action Plan, regulated entities were 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. However, with the recent withdrawal from the Kyoto Protocol, the future use of this mechanism may not occur.

(d) 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.

From December 7 to 18, 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to 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. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. 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 that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any; the proposals contained in the Updated Action Plan will be implemented.

The United States Environmental Protection Agency (the **EPA**) has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it will issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

Alberta

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

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

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the **Fund**) at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, 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.

Under the Alberta regulations, if the emissions remain at current levels, we would be required to purchase off-setting credits in 2011 of up to $500,000 from Alberta Environment. In 2011 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 current tax level is $25 per tonne of CO_2 equivalent. It is scheduled to increase to $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 partially came 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 GHG 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 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed offsets and emissions trading are currently in the consultation stage.

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 2011 reporting year.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the **MRGGA**) to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 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.

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 GHG regulations, existing and proposed, may at some time and under certain conditions 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, 2011.**

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 including ongoing credit and liquidity concerns;
- 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 a materially 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.

Table of Contents

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.

Our success depends in large measure on certain key and qualified 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.

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.

Table of Contents

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 and other financial systems 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.

We engage in hedging activities which could limit the full benefit of commodity price increases.

From time to time we enter into agreements to receive fixed prices for our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;

- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Table of Contents

Similarly, from time to time we may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, we will not benefit from the fluctuating exchange rate.

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 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 our 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 and storage facilities. United States federal and state and Canadian federal and provincial regulation of oil and gas production and transportation, general economic conditions, changes in supply and demand, market conditions, and other conditions affecting infrastructure systems and facilities 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.

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:

Table of Contents

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.

Reserve information contained herein includes 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, restrictions on certain operations such as the fracturing of wells, 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. Changes in, and the introduction of new, regulation may cause us to have to alter our operational practices, increase our compliance obligations and incur additional costs as a result.

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, increase our costs or delay or restrict our operations, all of which would have a material adverse impact on us.

Table of Contents

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 fire, explosion, blowouts, sour gas releases and spills or other environmental hazards, 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.

Potential conflicts of interest.

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.

Lindbergh SAGD Project Specific Risks

Our Lindbergh SAGD project will require substantial capital investment over the coming years. In addition to the above, there are certain additional risk factors associated with the development of our Lindbergh SAGD project. These include the following:

Early Stage of Development

There is a risk that design and construction of the facilities and infrastructure to support our Lindbergh oil sands pilot and any future commercial projects will not be completed on time, on budget or at all. Additionally, there is a risk that the Lindbergh pilot and any future commercial projects may have delays, interruptions of operations or increased costs due to many factors, including, without limitation:

inability to attract or retain sufficient numbers of qualified workers;

breakdown or failure of equipment or processes;

construction performance falling below expected levels of output or efficiency;

design errors;

non-performance by, or financial failure of, third-party contractors;

labour disputes, disruptions or declines in productivity;

increases in materials or labour costs;

conditions imposed by regulatory approvals;

delays induced by weather;

disruption or delays in availability of transportation services;

Table of Contents

- errors in construction;
- changes in project scope;
- unforeseen site surface or subsurface conditions;
- transportation or construction accidents;
- permit requirement violation;
- availability of water supplies;
- reservoir performance;
- energy supply disruption; and
- shortages of or delays in accessing drilling rigs and services.

The Lindbergh pilot project is not being constructed on a turn-key basis. Additionally, given the state of development of the Lindbergh project, various changes to the project may be made. Based upon current scheduling, the project is not expected to start commercial SAGD operations until 2014 at the earliest. The information contained herein related to the Lindbergh project, including, without limitation, reserve and economic evaluations, assumes receipt of all regulatory approvals and no material changes being made to the project or its scope.

The industry is in a period of substantial oil sands development and industrial activity. We will need to compete for equipment, supplies, services, and labour in this environment which could result in increased costs, shortages of goods and services that delay progress, or both. Increased competition for equipment, materials and labour may result in increased costs that could have a material adverse effect on our business, financial condition or results of operations. As such, there are risks associated with project cost estimates provided by us. Cost estimates are provided prior to pilot project results, completion of final scope design and detailed engineering needed to reduce the margin of error. Accordingly, actual costs may vary from estimates and these differences may be material.

Operating Costs

The operating costs of the Lindbergh project have the potential to vary considerably throughout the operating period and will be significant components of the cost of production of any petroleum products produced by the Lindbergh project. Project economics and our overall earnings may be reduced if increases in operating costs are incurred. Factors which could affect operating costs include, without limitation;

- the amount and cost of labour to operate the Lindbergh project;
- the cost of catalyst and chemicals;
- the actual steam oil ratio required to operate the SAGD well pairs;

- the cost of natural gas and electricity;
- power outages, particularly in winter when freeze-ups could occur;
- produced sand causing issues of erosion, hot spots and corrosion;
- reliability of the facilities;
- the maintenance cost of the facilities;
- the cost to transport sales products and the cost to dispose of certain by-products;
- the cost of insurance; and
- catastrophic events such as fires, earthquakes, storms or explosions.

Infrastructure for the Lindbergh Project

We will depend, to a large extent, on third party designers, contractors and suppliers to design and construct the necessary facilities and infrastructure for the Lindbergh project. We also anticipate that we will rely on certain infrastructure owned and operated or to be

Table of Contents

constructed by others, including, without limitation, pipelines for the transportation of diluent and produced bitumen to the market, natural gas, water source and disposal pipelines and electrical grid transmission lines for the provision and/or sale of electricity to us. The failure of any or all of these third parties to supply utilities, services or construct the infrastructure required to complete the Lindbergh project on a timely basis and on acceptable commercial terms would negatively impact our operation and financial results.

In-situ Extraction

Current SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam which is used in the recovery process. The amount of steam required in the production process can also vary and significantly impact costs. The performance of the reservoir can also impact the timing and levels of production using this technology.

Recovery of Bitumen

Recovering bitumen from oil sands involves particular risks and uncertainties. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. SAGD projects like Lindbergh are susceptible to loss of production, slowdowns, or restrictions on their ability to produce higher value products due to the interdependence of component systems. Severe weather conditions can cause reduced production and in some situations result in higher costs.

Access to Diluent Supplies at Favourable Prices

Bitumen is characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent, a hydrocarbon based diluting agent, is required to facilitate the transportation of bitumen. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport bitumen to market and correspondingly increasing our operating costs, decreasing our net revenues and negatively impacting the overall profitability of the Lindbergh oil sands project.

MARKET FOR SECURITIES

Prior to January 3, 2011 the Trust Units were listed on the NYSE under the symbol 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 Common Shares and Trust Units in 2011 as reported by the TSX and the NYSE.

	TSX		
2011	**($) High**	**($) Low**	**Volume**
Trust Units			
January (3 to 7)	13.04	12.76	2,364,625
Common Shares			
January (10 to 31)	13.44	12.45	25,781,087
February	12.79	12.00	16,919,005
March	13.80	11.98	19,256,750
April	13.96	12.77	13,117,658
May	13.37	12.23	12,644,657
June	12.81	11.56	13,588,895
July	12.84	11.95	10,912,849
August	12.47	9.63	15,570,618
September	11.36	9.33	12,595,787
October	10.91	8.48	15,778,533
November	11.05	9.84	20,245,324
December	11.18	10.39	22,478,714

NYSE

2011	(US$) High	(US$) Low	Volume
Common Shares			
January (3 to 31)	13.55	12.48	2,526,053
February	12.91	12.14	3,560,340
March	14.14	12.09	6,990,198
April	14.60	13.23	5,538,705
May	14.10	12.53	5,944,231
June	13.21	11.81	6,763,644
July	13.60	12.32	5,628,359
August	13.19	9.80	8,956,356
September	11.64	8.94	7,513,538
October	11.00	7.49	7,787,856
November	10.87	9.38	5,079,041
December	10.97	10.01	5,176,475

Table of Contents

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
John B. Zaozirny[2][3] Alberta, Canada	Chairman and Director (Director since 1988)	Vice Chairman of Canaccord Genuity Corp. since May 2010 and prior thereto Vice Chairman of Canaccord Financial Inc.
Derek W. Evans Alberta, Canada	President, Chief Executive Officer and Director (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.
Thomas A. Cumming[3][4][5] Alberta, Canada	Director (Director since 2000)	Business Consultant and Corporate Director.
Wayne K. Foo[2][4] Alberta, Canada	Director (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.
James D. McFarland[4][5][6] Alberta, Canada	Director (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.
Michael S. Parrett[2][3][5] Ontario, Canada	Director (Director since 2004)	Business Consultant and Corporate Director.
A. Terence Poole[2][5] Alberta, Canada	Director (Director since 2005)	Business Consultant since 2006; prior thereto Executive Vice President, Corporate Strategy and Development at Nova Chemicals Corporation.
D. Michael G. Stewart[3][4] Alberta, Canada	Director (Director since 2006)	Corporate Director.
Gillian Basford 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.
Douglas C. Bowles Alberta, Canada	Vice President and Controller	Vice President and Controller of Pengrowth.
James E.A. Causgrove Alberta, Canada	Senior Vice President, Operations and Engineering	Senior Vice President, Operations and Engineering of Pengrowth since September 8, 2011; prior thereto, Vice President, Production and Operations of Pengrowth.
Steve J. De Maio[7] 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).
Dean Evans Alberta, Canada	Treasurer	Treasurer of Pengrowth since February 2009; prior thereto Treasury Manager at ARC Resources Ltd.
Andrew D. Grasby 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).
Marlon J. McDougall Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Pengrowth since August 8, 2011; prior thereto, Vice President Operations & Chief Operating Officer of NAL Resources from December 2006 to June 2011.

Table of Contents

Name and Jurisdiction of Residence	Position with Pengrowth(1)	Principal Occupation
Robert W. Rosine 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).
Christopher G. Webster Alberta, Canada	Chief Financial Officer	Chief Financial Officer of Pengrowth.

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) Member of Corporate Governance and Nominating Committee.

(3) Member of Compensation Committee.

(4) Member of Reserves, Operations, Health, Safety and Environment Committee.

(5) Member of Audit and Risk Committee.

(6) 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.

(7) 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, 2011, the foregoing directors and officers, as a group, beneficially owned, directly or indirectly, 779,021 Common Shares or approximately 0.22 percent of the issued and outstanding Common Shares and held rights and options to acquire a further 1,786,623 Common Shares (assuming 100% vesting of all performance-based rights). The information as to shares beneficially owned, not being within our knowledge, has been furnished by the respective individuals.

The term of office for 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 ten 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.

Table of Contents

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 39 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 ExxonMobil affiliates in Canada, the US and western Europe. Mr. McFarland is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, the Society of Petroleum Engineers International, the Program Committee of the World Petroleum Council and the Institute of Corporate Directors. 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 is Chairman of Mongolia Minerals Corporation and a director of Sunshine Silver Mines Corporation, both private corporations. 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 2011 and 2010:

	2011 ($M)	2010 ($M)
Audit Fees	1,024	923
Audit Related Fees		
Tax Fees	35	80
All Other Fees	214	
Total	**1,273**	**1,003**

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.

Table of Contents

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 2011 and 2010 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. In addition, some members of our senior management team sit as directors of other corporations. Any such positions must be disclosed to the Board of Directors and approved by the Chief Executive Officer.

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.

Table of Contents

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 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, 2011.

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 Olympia Trust Company at its principal offices in the cities of Calgary, Alberta and Toronto, Ontario. 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 First Amending Agreement to the Amended and Restated Credit Agreement dated November 29, 2011 concerning our Credit Facility;

(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 an updated code of ethics on November 4, 2011. All Directors, officers, employees, consultants and contractors are required to accept the Code of Ethics annually.

During the year ended December 31, 2011, 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.

Table of Contents

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, Health, Safety and Environment Committee, a Code of Business Conduct and Ethics, a Corporate Disclosure Policy and an Insider Trading 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 s 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.

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 which relates to the Annual Meeting of Shareholders to be held on May 2, 2012. Additional financial information is contained in our comparative consolidated financial statements and associated management s discussion and analysis for the years ended December 31, 2011, 2010 and 2009.

Additional information relating to us may be found on SEDAR at www.sedar.com and on EDGAR at the SEC s website at www.sec.gov.

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

Table of Contents

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 **Company**):

1. We have evaluated the Company s reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

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

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 Company evaluated by us for the year ended December 31, 2011, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company 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 % discount rate - $M)			
			Audited	**Evaluated**	**Reviewed**	**Total**
GLJ Petroleum Consultants	January 16, 2012	Canada		4,810,534		4,810,534

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.

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

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.
EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 27, 2012.

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

APPENDIX A **PENGROWTH ENERGY CORPORATION** ANNUAL INFORMATION FORM

Table of Contents

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, 2011, 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, Health, Safety and Environment 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, Health, Safety and Environment 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, Health, Safety and Environment 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) *Bob Rosine*

Bob Rosine
Executive Vice President, Business Development
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
February 28, 2012

APPENDIX B **PENGROWTH ENERGY CORPORATION** ANNUAL INFORMATION FORM

Table of Contents

APPENDIX C

AUDIT AND RISK COMMITTEE

TERMS OF REFERENCE

PENGROWTH ENERGY CORPORATION	**Page**
Policies and Practices	**1 of 12**

TERMS OF REFERENCE

AUDIT AND RISK COMMITTEE
OBJECTIVES

The Audit and Risk Committee (the **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 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 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 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

Committee members must meet the requirements of applicable securities laws and each of the stock exchanges on which the shares of Pengrowth trade. The Committee will be comprised of three or more directors as determined by the Board. Each member of the 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 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.

APPENDIX C **PENGROWTH ENERGY CORPORATION** ANNUAL INFORMATION FORM

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 Committee shall be appointed by the Board.

MEETINGS AND MINUTES

The 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 Committee, the Chairman of the Board or the President and Chief Executive Officer (**CEO**) of Pengrowth. A notice of time and place of every meeting of the Committee shall be given in writing to each member of the 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 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 Committee shall require a majority of its members present in person or by telephone. If the chair of the Committee is not present at any meeting of the Committee, one of the other members of the Committee present at the meeting will be chosen to preside by a majority of the members of the Committee present at that meeting.

The Chairman of the Board and the CEO shall be available to advise the Committee, shall receive notice of meetings and may attend meetings of the 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 Committee shall hold *in camera* sessions, without management present, at every meeting of the Committee.

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

The Committee shall appoint a member of the 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 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 Committee. All information reviewed and discussed by the 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

<u>REVIEW PROCEDURES</u>

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

1. Review and reassess the adequacy of the 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,

Table of Contents

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 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 Committee shall advise the external auditors of their accountability to the 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 Committee. The 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 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 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.

APPENDIX C **PENGROWTH ENERGY CORPORATION** ANNUAL INFORMATION FORM

Table of Contents

Discretionary Duties

The Committee s responsibilities may, at the 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 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 Chairman of the Board and the President and CEO.

External Auditors

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

2.

The 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 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 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.

APPENDIX C **PENGROWTH ENERGY CORPORATION** ANNUAL INFORMATION FORM

Table of Contents

COMMUNICATION, AUTHORITY TO ENGAGE ADVISORS AND EXPENSES

The 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 Committee, on a confidential basis, any concerns relating to matters over which the Committee has oversight responsibilities.

The 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 Committee that are deemed necessary or appropriate by the Committee in order to carry out its duties.

Adopted by the Board of Pengrowth on November 4, 2011.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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).

(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 listed 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.

Table of Contents

C-2

to Appendix C

For 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. When the issuer is a trust, officers or employees of the trustee(s) who perform policy-making functions for the trust are deemed officers of the trust.

Table of Contents

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Stock Exchange Listings

Toronto Stock Exchange: **PGF** | New York Stock Exchange: **PGH**

APPENDIX B

MANAGEMENT S DISCUSSION AND ANALYSIS

Table of Contents

interest rates, the proceeds of anticipated divestitures, the amount of future cash dividends paid by Pengrowth, the cost of expanding our property holdings, our ability to obtain labour and equipment in a timely manner to carry out development activities, our ability to market our oil and natural gas successfully to current and new customers, the impact of increasing competition, our ability to obtain financing on acceptable terms, our ability to add production and reserves through our development, exploitation 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; Pengrowth s ability to replace and expand oil and gas reserves; ability to produce those reserves; production may be impacted by unforeseen events such as equipment failure and weather related causes; 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; Pengrowth s ability to access external sources of debt and equity capital; the implementation of International Financial Reporting Standards; and the implementation of greenhouse gas emissions legislation. Further information regarding these factors may be found under the heading Business Risks herein and under Risk Factors in Pengrowth s most recent Annual Information Form (AIF), and in Pengrowth s most recent consolidated financial statements, management information circular, quarterly reports, material change reports and news releases. Copies of Pengrowth s Canadian public filings are available on SEDAR at www.sedar.com. Pengrowth s U.S. public filings, including the most recent annual report form 40-F as supplemented by its filings on form 6-K, are available at www.sec.gov.

Pengrowth cautions 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 MD&A are made as of the date of this MD&A and Pengrowth does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, except as required by law. The forward-looking statements in this document are provided for the limited purpose of enabling current and potential investors to evaluate an investment in Pengrowth. Readers are cautioned that such statements may not be appropriate, and should not be used for other purposes.

The forward-looking statements contained in this MD&A are expressly qualified by this cautionary statement.

ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On January 1, 2011, Pengrowth adopted International Financial Reporting Standards (IFRS) for financial reporting purposes, using a transition date of January 1, 2010. The financial statements for the year ended December 31, 2011, have been prepared in accordance with IFRS, and herein after referred to as GAAP. Required comparative information has been restated from previously published financial statements which were prepared in accordance with Canadian Generally Accepted Accounting Principles (previous GAAP). For additional information regarding the changes see section International Financial Reporting Standards (IFRS) in this MD&A.

CRITICAL ACCOUNTING ESTIMATES

The financial statements are prepared in accordance with IFRS. Management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period ended. Certain of these estimates may change from period to period resulting in a material impact on Pengrowth s results of operations, financial position, and change in financial position.

The following describes Pengrowth s significant critical accounting estimates.

Estimating oil and gas reserves

Pengrowth engages a qualified, independent oil and gas reserves evaluator to perform an estimation of the Corporation s oil and gas reserves at least annually. Reserves form the basis for the calculation of depletion charges and assessment of impairment of oil and gas assets. Reserves are estimated using the reserve definitions and guidelines prescribed by National Instrument 51-101 (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (COGEH).

Table of Contents

Proved plus probable reserves are defined as the best estimate of quantities of oil, natural gas and related substances estimated to be commercially recoverable from known accumulations, from a given date forward, based on drilling, geological, geophysical and engineering data, the use of established technology and specified economic conditions. It is equally likely that the actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves. The estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes and reservoir performance or a change in Pengrowth s plans with respect to future development or operating practices.

Determination of Cash Generating Units (CGUs)

CGUs are the smallest group of assets that generate cash inflows largely independent from other assets or group of assets. Determination of what constitutes a CGU is subject to management s judgment. The asset composition of a CGU can directly impact the recoverability of the assets included therein. The recoverability of development and production asset carrying values are assessed at the CGU level. In assessing the recoverability of oil and gas properties, each CGU s carrying value is compared to its recoverable amount, defined as the greater of fair value less costs to sell and value in use.

Asset Retirement Obligation

Pengrowth estimates obligations under environmental regulations in respect of decommissioning and site restoration. These obligations are determined based on the expected present value of expenses required in the process of plugging and abandoning wells, dismantling of wellheads, production and transportation facilities and restoration of producing areas in accordance with relevant legislation, discounted from the date when expenses are expected to be incurred. Most of the abandonment of Pengrowth s wells is estimated to take place far in the future. Therefore, changes in estimated timing of future expenses, estimated logistics of performing abandonment work and the discount rate used to present value future expenses could have a significant effect on the carrying amount of the decommissioning provision.

Impairment testing

Impairment testing of property, plant and equipment is completed for each of Pengrowth s CGUs. Impairment testing is based on estimates of proved plus probable reserves, production rates, oil and natural gas prices, future costs, discount rates and other relevant assumptions. The impairment assessment of goodwill is based on the estimated fair value of Pengrowth s CGUs. By their nature, these estimates are subject to measurement uncertainty and may impact the financial statements of future periods.

Valuation of trade and other receivables, and prepayments to suppliers

Management estimates the likelihood of the collection of trade and other receivables and recovery of prepayments based on an analysis of individual accounts. Factors taken into consideration include the aging of receivables in comparison with the credit terms allowed to customers and the financial position and collection history with the customer. Should actual collections be less than estimates, Pengrowth would be required to record an additional expense.

COMPARATIVE FIGURES

Certain changes to the presentation of oil and gas sales, operating expenses, and transportation on the Statements of Income were made in 2011, and as such comparative periods have been restated with no impact to net income. Management believes that these presentation changes better reflect Pengrowth s operating results.

ADDITIONAL GAAP MEASURE

Funds Flow from Operations

Pengrowth uses Funds Flow from Operations, a Generally Accepted Accounting Principles (GAAP) measure that is not defined under IFRS. Management believes that in addition to cash provided by operations, Funds Flow from Operations, as reported in the Consolidated Statements of Cash Flow is a useful supplemental measure as it provides an indication of the funds generated by Pengrowth s principal business activities prior to consideration of changes in working capital and remediation expenditures. Pengrowth considers this to be a key measure of performance as it demonstrates its ability to generate cash flow necessary to fund dividends and capital investments.

NON-GAAP FINANCIAL MEASURES

This MD&A refers to certain financial measures that are not determined in accordance with IFRS. These measures do not have standardized meanings and may not be comparable to similar measures presented by other oil and gas companies. Measures such as operating netbacks do not have standardized meanings prescribed by GAAP. See the section of this MD&A entitled Operating Netbacks for a discussion of the calculation.

The current level of capital expenditures funded through retained cash flow, as compared to debt or equity, can be determined when it is compared to the difference in Funds Flow from Operations and dividends paid as shown on the Statement of Cash Flow.

Management monitors Pengrowth s capital structure using non-GAAP financial metrics. The two metrics are Total Debt to the trailing twelve months Earnings Before Interest, Taxes, Depletion, Depreciation, Amortization, Accretion, and other non-cash items (EBITDA) and Total Debt to Total Capitalization. Total Debt is the sum of working capital deficit and long term debt as shown on the Balance Sheet, and Total Capitalization is the sum of Total Debt and Shareholders Equity.

Payout Ratio is a term used to evaluate financial flexibility and the capacity to fund dividends. Payout Ratio is defined on a percentage basis as dividends declared divided by Funds Flow from Operations.

Adjusted Net Income

Management believes that in addition to net income, Adjusted Net Income is a useful supplemental measure as it reflects the underlying performance of Pengrowth s business activities by excluding the after tax effect of certain mark-to-market non-cash items that may significantly impact net income from period to period based on movements in future commodity prices and foreign exchange rates.

OPERATIONAL MEASURES

The reserves and production in this MD&A refer to company interest reserves or production that is Pengrowth s working interest share of production or reserves prior to the deduction of Crown and other royalties plus any Pengrowth owned royalty interest in production or reserves at the wellhead. Company interest is more fully described in the AIF.

When converting natural gas to equivalent barrels of oil within this MD&A, Pengrowth uses the industry standard of six Mcf to one boe. Barrels of oil equivalent may be misleading, particularly if used in isolation; a conversion ratio of six Mcf of natural gas to one boe is based on an energy equivalency conversion and does not represent a value equivalency at the wellhead. Production volumes, revenues and reserves are reported on a company interest gross basis (before royalties) in accordance with Canadian practice.

Pengrowth s ability to grow both reserves and production can be measured with the following metrics: Reserves per debt adjusted share and production per debt adjusted share. Reserves per debt adjusted share are measured using year-end proved plus probable reserves and the number of common shares outstanding at year-end. The measurements are debt-adjusted by assuming additional shares are issued at year-end share prices to replace year-end long-term debt outstanding.

Production per debt adjusted share is measured in respect of the average production for the year and the weighted average number of common shares outstanding during the year. The measurements are debt-adjusted by assuming additional shares are issued at year-end share prices to replace year-end long-term debt outstanding.

Recycle ratio is a measure of value creation for each dollar spent. This measure is calculated as operating netback per boe divided by Finding and Development (F&D) cost per boe and can also be calculated using Finding, Development & Acquisition (FD&A) cost per boe. Recycle ratio can be calculated including or excluding Future Development Capital (FDC).

CURRENCY

All amounts are stated in Canadian dollars unless otherwise specified.

Pengrowth s fourth quarter and annual results for 2011 are contained within this MD&A.

Table of Contents

2011 AND 2012 GUIDANCE AND 2011 FINANCIAL HIGHLIGHTS

The following table provides a summary of the 2011 and 2012 Guidance and a review of 2011 actual results.

	2011 Guidance	2011 Actual	2011 Variance	2012 Guidance
Annual Average Production (boe/d)	72,000 - 74,000	73,973		74,500 - 76,500 (1)
Exit Production (2)	75,500 - 76,500	76,789		78,000 (1)
Royalty Expense (% of Sales) (3)	20.0	19.3	(0.7)	20.0
Operating Expense ($/boe)	14.45 (4)	14.15	(0.30)	13.89 (4)
G&A Expense (cash & non-cash) ($/boe)	3.00(4)	2.79	(0.21)	2.68(4)
Net capital expenditures ($ millions) (5)	610.0	609.1	(0.9)	625.0

(1) Based on production guidance levels provided on January 24, 2012 and excludes Lindbergh volumes.

(2) Exit production based on December average.

(3) Royalty expense as a % of sales excludes the impact of commodity risk management contracts.

(4) Operating and G&A expense ($/boe) assume the midpoint of production guidance.

(5) Net capital expenditures includes Drilling Royalty Credits and capitalized stock based compensation.

Full year and exit production was at the high end of Guidance due to favourable drilling results in the fourth quarter.

Operating expense and G&A per boe were below Guidance primarily due to increased volumes in the fourth quarter.

Pengrowth will include net operating income or loss associated with the Lindbergh Steam Assisted Gravity Drainage (SAGD) project in net capital expenditures until commerciality is declared, pursuant to Pengrowth s Exploration and Evaluation Assets (E&E Assets) accounting policy (see Note 7 to the financial statements for additional information).

FINANCIAL HIGHLIGHTS

(monetary amounts in millions, except per boe amounts or as otherwise stated)	Three months ended Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Twelve months ended Dec 31, 2011	Dec 31, 2010
Production (boe/d)	76,691	74,568	74,953	73,973	74,693
Net capital expenditures (1)	$ 142.1	$ 163.8	$ 130.9	$ 609.1	$ 333.8
Funds flow from operations (2)	$ 171.1	$ 150.4	$ 139.9	$ 620.0	$ 626.2
Operating netback ($/boe) (2) (3)	$ 29.99	$ 27.15	$ 25.02	$ 28.45	$ 26.92
Adjusted Net Income (4)	$ 22.3	$ 22.9	$ 40.7	$ 110.9	$ 208.4
Net (loss) income	$ (9.0)	$ (0.5)	$ (152.0)	$ 84.5	$ 149.8
Included in net (loss) income :					
Realized gain (loss) on commodity risk management (5)	$ 2.7	$ 14.2	$ 19.1	$ 16.8	$ 75.1

Unrealized (loss) gain on commodity risk management [5]	$ (102.9)	$ 58.1	$ (52.5)	$ (40.0)	$ 6.9
Unrealized foreign exchange gain (loss) [5]	$ 29.2	$ (76.4)	$ 29.7	$ (19.1)	$ 49.9
Non-cash gain on investments [5]	$ 23.0	$	$	$ 23.0	$ 73.8
Deferred tax reduction (expense)	$ 13.7	$ (16.1)	$ (165.9)	$ (22.3)	$ (171.3)

(1) Net capital expenditures includes Drilling Royalty Credits and capitalized stock based compensation.

(2) Prior periods restated to conform to presentation in the current period.

(3) Includes the impact of realized commodity risk management contracts.

(4) See definition under section Non-GAAP Financial Measures .

(5) Pre-tax amount.

Table of Contents

Funds Flow from Operations

($ millions)	Q4	% Change	Full Year	% Change
2010 Funds Flow from Operations [1]	139.9		626.2	
Volume variance	9.8	7	(16.0)	(3)
Price variance	49.2	35	154.4	25
Realized gains on risk management contracts	16.3	(12)	(58.2)	(9)
Other Income	1.6	1	4.8	1
Royalty expense	(11.4)	(8)	(25.2)	(4)
Drilling Credits [2]			(16.7)	(3)
Expenses:				
Operating	5.2	4	(24.8)	(4)
Transportation	0.9		(0.6)	
Cash G&A	(4.2)	(3)	(18.0)	(3)
Interest & Financing	(1.5)	(1)	(5.4)	(1)
Realized foreign exchange	(0.5)		0.5	
Other Expenses	(1.6)	(1)	(1.0)	
2011 Funds Flow from Operations [1]	171.1	22	620.0	(1)

(1) Prior period restated to conform to presentation in the current period.

(2) In the second quarter of 2010, a $16.7 million gain was recorded related to purchased drilling credits and a property disposition where the proceeds received consisted of drilling credits in excess of the value of the assets sold.

Funds Flow from Operations increased 22 percent in the fourth quarter of 2011 compared to the same period in 2010. The increase was driven by higher commodity prices for liquids and increased fourth quarter production partially offset by lower realized gains on risk management contracts and lower natural gas prices. Funds Flow from Operations decreased one percent on a year-over-year basis. The decrease is due to lower realized gains on risk management contracts, higher operating costs primarily due to increased power costs, higher royalties and G&A costs, lower production volumes, and the absence of gains from purchasing third party drilling credits, mostly offset by higher liquids commodity prices.

Price Sensitivity

The following table illustrates the sensitivity of Funds Flow from Operations to changes in commodity prices.

				Estimated Impact on 12 month Cash Flow [2][3]
Estimated Commodity Price Environment [1]		Assumption	Change	($ millions)
WTI[4] Oil Price	US$/bbl	$107.75	$1.00	
Light Oil Production				7.1
Heavy Oil Production				1.8
NGL Production				2.9
				11.8
AECO Natural Gas Price				
Natural Gas Production	Cdn$/Mcf	$2.39	$0.10	6.1

(1) Calculations are performed independently and are not indicative of actual results when multiple variables change at the same time.

(2) Commodity price is based on an estimation of the 12 month forward price curve at February 28, 2012 and does not include the impact of risk management contracts.

(3) The calculated impact on revenue/cash flow is only applicable within a limited range of the change indicated and is based on production guidance levels contained herein.

(4) West Texas Intermediate.

Table of Contents

Net Income or Loss

For the fourth quarter of 2011, a net loss of $9.0 million was recorded, compared to a net loss of $0.5 million in the third quarter of 2011, representing an increase in the loss of $8.5 million. The larger loss in the fourth quarter of 2011 is primarily due to non-cash losses of $28.0 million (net of deferred tax) noted below and summarized in the Adjusted Net Income reconciliation table, which more than offset the increase in Funds Flow from Operations of $20.7 million:

A $120.2 million (net of deferred tax) adverse change from unrealized commodity risk management contracts comprised of an unrealized loss in the fourth quarter of $102.9 million ($76.8 million, net of deferred tax) compared to an unrealized gain of $58.1 million ($43.4 million, net of deferred tax) in the third quarter of 2011.

A $92.2 million (net of deferred tax) favourable impact from unrealized foreign exchange comprised of a gain in the fourth quarter of $29.2 million ($25.5 million, net of deferred tax) compared to an unrealized foreign exchange loss of $76.4 million ($66.7 million, net of deferred tax) in the third quarter of 2011.

A $143.0 million increase in net income was recorded in the fourth quarter of 2011 compared to the same period last year primarily due to the IFRS non-cash tax effect of changing to a corporate structure of $180.8 million, which was recorded in 2010. Funds Flow from Operations increased $31.2 million in the fourth quarter of 2011 compared to 2010. In addition, other non-cash losses of $59.5 million (net of deferred tax), detailed below, affected net income in the fourth quarter of 2011 compared to the same period in 2010:

A $39.1 million (net of deferred tax) adverse change from unrealized commodity risk management contracts comprised of an unrealized loss of $102.9 million ($76.8 million, net of deferred tax) in the fourth quarter of 2011 compared to an unrealized loss of $52.5 million ($37.7 million, net of deferred tax) in the same period in 2010.

An impairment charge of $27.4 million ($20.4 million, net of deferred tax) in the fourth quarter of 2011 relating to the Groundbirch CGU.

On a year-over-year basis net income decreased $65.3 million from $149.8 million in 2010 to $84.5 million in 2011. The reduction in 2011 is primarily due to changes in certain non-cash items noted below, some of which are summarized in the Adjusted Net Income reconciliation:

A $34.8 million (net of deferred tax) adverse change from unrealized commodity risk management contracts comprised of an unrealized loss of $40.0 million in 2011 ($29.8 million, net of deferred tax) compared to an unrealized gain of $6.9 million ($5.0 million, net of deferred tax) in 2010.

A $60.3 million (net of deferred tax) unfavourable impact from unrealized foreign exchange comprised of an unrealized loss of $19.1 million in 2011 ($16.7 million, net of deferred tax) compared to an unrealized gain of $49.9 million ($43.6 million, net of deferred tax) in 2010.

A $53.7 million (net of deferred tax) adverse change from gains on investments comprised of a $23.0 million investment gain in 2011 ($20.1 million, net of deferred tax) in 2011 as compared to a $73.8 million gain ($73.8 million, net of deferred tax) on Monterey shares in 2010.

2011 also includes an impairment charge of $27.4 million ($20.4 million, net of deferred tax) relating to the Groundbirch CGU.

Partially offsetting the above were two significant deferred tax items in 2010 which resulted in the 2010 deferred tax expense being higher than 2011 by $103.2 million. Tax deductible distributions made by the Trust in 2010 have been replaced by taxable dividends made by the Corporation in 2011, resulting in the deferred tax expense being lower in 2010 by $77.6 million. This was more than offset by the absence of a $180.8 million IFRS charge to deferred tax expense in 2010 relating to changing to a corporate structure.

Table of Contents

Adjusted Net Income

The following table provides a reconciliation of net income to Adjusted Net Income:

	Three months ended			Twelve months ended	
(monetary amounts in millions)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Net (loss) income	$ (9.0)	$ (0.5)	$ (152.0)	$ 84.5	$ 149.8
Addback (deduct) certain non-cash items included in net (loss) income :					
Unrealized (gain) loss on commodity risk management	102.9	(58.1)	52.5	40.0	(6.9)
Unrealized foreign exchange (gain) loss	(29.2)	76.4	(29.7)	19.1	(49.9)
Non-cash (gain) on investments	(23.0)			(23.0)	(73.8)
Tax effect on non-cash items above	(19.4)	5.1	(10.9)	(9.7)	8.4
Tax effect on corporate conversion			180.8		180.8
Adjusted net income	$ 22.3	$ 22.9	$ 40.7	$ 110.9	$ 208.4

Adjusted Net Income of $22.3 million in the fourth quarter of 2011 was slightly lower compared to the Adjusted Net Income of $22.9 million in the third quarter of 2011 primarily due to increased Funds Flow from Operations offset by an impairment of assets.

In the fourth quarter of 2011, Pengrowth s Adjusted Net Income was $22.3 million as compared to $40.7 million in the fourth quarter of 2010. The $18.4 million decrease was due primarily to the previously mentioned impairment charge of $20.4 million net of deferred tax ($27.4 million pre-tax) and higher deferred tax expense this year as the prior year had $25.5 million of tax deductible distributions as a Trust. These items were partly offset by an increase in Funds Flow from Operations of $31.2 million.

Adjusted Net Income for the full year 2011 was $97.5 million lower than the same period in 2010 mainly as a result of the previously described impairment charge of $20.4 million net of deferred tax ($27.4 million pre-tax), and a $77.6 million increase to deferred income tax expense this year as tax deductible distributions made by the Trust in 2010 were replaced by taxable dividends made by the Corporation in 2011. A $6.2 million reduction in Funds Flow from Operations also contributed to the decrease.

RESULTS OF OPERATIONS

(All volumes, wells and spending amounts stated below reflect Pengrowth s net working interest unless otherwise stated.)

CAPITAL EXPENDITURES

For the full year of 2011, Pengrowth spent $609.1 million on net capital expenditures excluding property acquisitions and dispositions. Approximately 87 percent of net capital expenditures was spent on drilling, completions and facilities with the remaining 13 percent spent on capital not directly adding reserves or production.

	Three months ended			Twelve months ended	
($ millions)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Drilling, completions and facilities	$ 124.6	$ 152.7	$ 120.4	$ 533.5	$ 300.8
Land & Seismic acquisitions (1)	6.9	(0.4)	4.5	20.6	11.5
Maintenance capital	12.2	10.1	7.5	51.7	41.0
Development capital	143.7	162.4	132.4	605.8	353.3
Other capital (2) (3)	(0.8)	3.0	1.9	5.7	4.4
Drilling Royalty Credits	(0.8)	(1.6)	(3.4)	(2.4)	(23.9)
Net capital expenditures (4)	142.1	163.8	130.9	609.1	333.8
Property acquisitions		5.5	0.1	8.6	20.2
Proceeds on property dispositions	(9.5)	(1.7)	(12.4)	(16.9)	(60.7)

Net capital expenditures and acquisitions	$ 132.6	$ 167.6	$ 118.6	$ 600.8	$ 293.3

(1) Seismic acquisitions are net of seismic sales revenue.

(2) Other capital includes equipment inventory and material transfers.

(3) Prior periods restated to conform to presentation in the current period.

(4) Net capital expenditures includes capitalized stock based compensation of $0.6 million for 2011 and will therefore not agree to the Statement of Cash Flow.

Table of Contents

DRILLING ACTIVITY

Pengrowth participated in the drilling of 241 gross wells (122.6 net wells) in 2011.

	Q4 2011		Q3 2011		Q2 2011		Q1 2011		Full Year 2011	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Focus Areas [1]										
Swan Hills	16	10.5	17	11.1	23	17.9	14	8.6	70	48.1
Groundbirch			1	1.0			3	3.0	4	4.0
Lindbergh	13	13.0	1	1.0	2	2.0	2	2.0	18	18.0
Bodo Polymer Project			30	30.0	5	5.0			35	35.0
Olds	2	0.4	2	1.5			5	2.9	9	4.8
Other Areas [1]	27	1.7	35	5.0	22	3.0	21	3.0	105	12.7
Total wells drilled	58	25.6	86	49.6	52	27.9	45	19.5	241	122.6

(1) Drilling activity reflects both operated and partner operated properties.

DEVELOPMENT CAPITAL ACTIVITIES

Pengrowth s capital spending breakdown by area is as follows:

($ millions)	Q4 2011	Q3 2011	Q2 2011	Q1 2011	Full Year 2011
Focus Areas [1]					
Swan Hills	$ 64.8	81.8	93.3	42.2	$ 282.1
Groundbirch	1.0	18.5	9.0	42.1	70.6
Lindbergh	34.1	13.6	10.2	3.5	61.4
Bodo Polymer Project	5.1	19.6	4.6		29.3
Olds	8.5	11.0	10.3	20.0	49.8
	113.5	144.5	127.4	107.8	493.2
Other Areas [2]	11.1	8.2	7.5	13.5	40.3
Drilling, completions & facilities	124.6	152.7	134.9	121.3	533.5
Maintenance	12.2	10.1	12.1	17.3	51.7
Land & Seismic Acquisitions	6.9	(0.4)	12.7	1.4	20.6
Other [2]	(0.8)	3.0	2.8	0.7	5.7
Drilling Royalty Credits	(0.8)	(1.6)			(2.4)
Net capital expenditures [3]	$ 142.1	163.8	162.5	140.7	$ 609.1

(1) Spending amounts reflect the activity for both operated and partner operated properties.

(2) Prior periods restated to conform to presentation in the current period.

(3) Net capital expenditures includes capitalized stock based compensation of $0.6 million.

Focus Areas

(Pengrowth references average well test results for certain properties. These results are not necessarily representative of long-term well performance or ultimate recoveries.)

Swan Hills Trend

With a net estimated 2.3 billion barrels of 42° API original oil in place in the Beaverhill Lake formation (Energy Resources Conservation Board estimate), the Swan Hills Trend is the most significant conventional oil resource area across Pengrowth s land base. This extensive carbonate oil reservoir provides Pengrowth with significant opportunities to put its expertise in horizontal drilling and multi-stage acid fracturing of carbonate reservoirs to work on its operated interests in Judy Creek, Carson Creek, House Mountain, Deer Mountain and Virginia Hills. Success in 2010 across the Swan Hills Trend drove increased activity in 2011.

During the fourth quarter, 10 operated wells (9.3 net) were drilled. Two of the wells were completed and tested with average five day initial production (IP) rates of over 600 boe per day per well and are anticipated to be tied-in during the first quarter of 2012. The remaining eight wells drilled in the fourth quarter are expected to be completed, tested and tied-in during the first quarter of 2012. Activity during the fourth quarter also included bringing on stream 11 operated wells (10.3 net) drilled and completed in the second and third quarters with average five day IP rates in excess of 690 boe per day per well.

Table of Contents

For full year 2011, a total of 46 operated wells (43.7 net) were drilled. Pengrowth brought on stream 36 operated wells (34.9 net) in 2011 with average five day IP rates in excess of 500 boe per day per well.

At year end, Pengrowth had two rigs drilling in the Swan Hills area and anticipates that a multi-rig drilling program will continue through 2012.

Lindbergh Steam Assisted Gravity Drainage (SAGD) Project

Construction of the central processing facility, well-pad and surface pipelines at the Lindbergh SAGD Pilot Facility continued through the fourth quarter in preparation for commissioning activities which commenced in January 2012. Two SAGD well-pairs (two producers and two injectors) were drilled and completed in the fourth quarter and nine core-holes were completed as part of the continuing resource assessment and validation in the Lindbergh area. First steam injection commenced essentially on time and budget in early February 2012.

For full year 2011, 18 gross wells (18.0 net) were drilled, with four being the well-pairs and 14 being core-holes. Data from the new wells have been incorporated by GLJ Petroleum Consultants Ltd. in re-assessing the Lindbergh Contingent Resource volumes, which will be filed with Pengrowth s AIF.

Groundbirch

The fourth quarter saw little activity in the Groundbirch area as the natural gas price decline shifted spending to liquids projects with more robust economics.

During 2011, four Montney horizontal wells (4.0 net wells) were drilled, completed and tied-in. Of the four wells, one came on stream early in the second quarter, with the other three wells coming on stream late in the third quarter. The 30 day IP rates for these four wells averaged approximately 550 boe per day. Pengrowth does not anticipate similar activity levels at Groundbirch in 2012.

Olds

In the fourth quarter of 2011 Pengrowth s first Mannville well, drilled in the third quarter, was tied-in and had a 30 day IP rate in excess of 500 boe per day.

In 2011 Pengrowth continued with the liquids rich gas program, tying-in a well drilled late in 2010 and drilling and completing three additional wells. These four Elkton wells had average 30 day IP rates of 480 boe per day with 50 bbls per MMcf liquid yield. These positive results have validated additional well locations for 2012.

East Bodo and Cactus

The East Bodo and Cactus heavy oil properties which straddle the Alberta-Saskatchewan border produce primarily from the McLaren and Lloydminster formations. These properties produce heavy oil through a combination of water flooding with enhanced oil recovery through the injection of polymer.

In 2011, positive results from Pengrowth s ongoing polymer flood in the Lloydminster formation at East Bodo led to an additional 35 wells being drilled in the third quarter of 2011.

Completion and tie-in operations were executed during the fourth quarter on 26 producers and nine injectors. At the end of 2011 this project was ramping up and had added approximately 360 boe per day of production to Pengrowth s exit rate.

2012 Capital Program

Pengrowth currently anticipates a 2012 capital program, excluding acquisitions, of $625 million, an increase of three percent from 2011 net capital expenditures of $609.1 million. Pengrowth s operated 2012 capital program is 100 percent focused on development of oil and liquids rich gas plays, with the majority of the capital to be spent in the three key areas of Swan Hills ($255 million), the Olds area ($85 million) and the Lindbergh SAGD ($59 million).

Table of Contents

RESERVES AND PERFORMANCE MEASURES

Reserves Company Interest

Reserves Summary	2011	2010	2009
Proved Reserves			
Drill + Revisions + Improved Recovery (mmboe) for the year	41.0	20.5	11.3
Net Acquisitions (Dispositions) (mmboe) for the year	(0.2)	11.2	(0.9)
Total Proved Reserves at period end	234.9	221.0	216.6
Proved Reserve replacement ratio excluding net acquisitions	152%	75%	39%
Proved Reserve replacement ratio including net acquisitions	151%	116%	36%
Proved plus Probable Reserves (P+P)			
Drill + Revisions + Improved Recovery (mmboe) for the year	39.3	27.1	2.6
Net Acquisitions (Dispositions) (mmboe) for the year	(0.3)	22.8	(1.3)
Total Proved plus Probable Reserves at period end	330.5	318.4	295.7
Total Production (MMboe)	27.0	27.3	29.0
P+P Reserve replacement ratio excluding net acquisitions	146%	99%	9%
P+P Reserve replacement ratio including net acquisitions	145%	183%	4%

Net capital expenditures increased 82 percent to $609.1 million in 2011 compared to $333.8 million in 2010. This increased capital spending resulted in higher reserve additions from drilling and revisions in 2011 compared to the previous year. New reserve additions from drilling and improved recovery projects amounted to 25.5 MMboe proved and 30.0 MMboe total proved plus probable internally replacing 152 percent of proved and 146 percent of proved plus probable reserves. Most significant were drilling extensions in our resource plays at Groundbirch, Judy Creek, Harmattan and Carson Creek and the implementation of a polymer flood in the East Bodo heavy oil property. In addition, technical revisions due to improved performance resulted in a net reserve increase of 15.6 MMboe proved and 9.3 MMboe total proved plus probable, primarily in Harmattan, Quirk Creek, Jenner and Carson Creek.

Further details of Pengrowth s 2011 year-end reserves, Finding and Development (F&D) and Finding, Development & Acquisition (FD&A) calculations are provided in the AIF which is filed on SEDAR (www.sedar.com) or the 40-F filed on Edgar (www.sec.gov).

Performance Measures

Finding & Development Costs & Recycle Ratio	2011	2010	2009	3 year weighted average
Excluding Net Acquisitions (F&D)				
Excluding Changes in FDC				
Recycle Ratio [(1) (3)]	1.9	2.2	0.3	1.7
F&D costs per boe proved plus probable	$ 15.34	$ 12.15	$ 78.47	$ 16.44
Including Changes in FDC				
Recycle Ratio [(1) (3)]	1.4	1.8	0.9	1.5
F&D costs per boe proved plus probable	$ 20.12	$ 15.32	$ 30.81	$ 18.63
Including Net Acquisitions (FD&A)				
Excluding Changes in FDC				
Recycle Ratio [(2) (3)]	1.9	1.8	0.2	1.6
FD&A costs per boe proved plus probable	$ 15.23	$ 14.61	$ 151.41	$ 16.84
Including Changes in FDC				
Recycle Ratio [(2) (3)]	1.4	1.5	0.5	1.4
FD&A costs per boe proved plus probable	$ 20.04	$ 18.46	$ 57.15	$ 19.69

(1) Recycle Ratio is calculated as operating netback per boe divided by F&D costs per boe based on proved plus probable reserves.

(2) Recycle Ratio is calculated as operating netback per boe divided by FD&A costs per boe based on proved plus probable reserves.

(3) Prior period restated to conform to presentation in the current period.

Table of Contents

The 2011 total proved plus probable F&D cost, including changes in Future Development Capital (FDC), was $20.12 per boe, a 31% increase from the 2010 F&D cost. The increase over last year is a reflection of a higher proportion of spending being made on oil and liquids rich gas projects as compared to dry gas projects in prior years. Also contributing to higher F&D costs is the accelerated pace and increasing costs for services associated with horizontal drilling and multi-stage frac completions for wells Pengrowth drilled in various resource plays. Drilling activity increased, particularly in the Swan Hills Trend, and proved plus probable reserve additions were 45 percent higher than in 2010.

Recycle ratio is an important performance measure in assessing investment profitability and provides a comparison to our competitors. Pengrowth s operating results and capital program in 2011 yielded a recycle ratio, excluding net acquisitions and including changes in FDC, of 1.4, in line with the three year average of 1.5. The decrease from the prior year is negatively impacted by the effect of declining natural gas prices on the average netback.

Pengrowth s goal over longer periods is to maintain or modestly grow production and reserves per debt adjusted share, while continuing to pay a prudent dividend. The trend in recent years for production per debt adjusted share has been relatively flat, but decreased slightly in 2011. Production fell below expectations in 2011 due to some uncontrollable external events in the first half of the year. Forest fires, power outages and unscheduled pipeline outages in Northern Alberta led to production being shut-in, while prolonged facility maintenance activities and severe wet weather limited access and transportation.

On a debt adjusted basis, total proved plus probable reserves per share also decreased in 2011, notwithstanding an overall reserve replacement ratio of 146% for the year. Pengrowth s aggressive capital program for 2012 is targeting to restore reserve and production growth. Exiting 2011 at 76,789 boe per day is a positive step which Pengrowth intends to build on.

Other Performance Measures	2011	2010	2009
Production per debt adjusted share (boe/share) (1)	0.06	0.07	0.08
Reserves per debt adjusted share (boe/share) (1)	0.73	0.78	0.74

(1) Debt adjusted shares equals the shares outstanding plus the number of shares needed to retire all of the debt at the year-end share price of $10.76 in 2011, $12.78 in 2010 and $10.15 in 2009.

PRODUCTION

	Three months ended						Twelve months ended			
Daily production	Dec 31, 2011	% of total	Sept 30, 2011	% of total	Dec 31, 2010	% of total	Dec 31, 2011	% of total	Dec 31, 2010	% of total
Light oil (bbls)	22,935	30	21,163	28	21,762	29	21,455	29	21,743	29
Heavy oil (bbls)	6,448	8	6,387	9	6,673	9	6,425	9	6,789	9
Natural gas liquids (bbls)	10,478	14	10,426	14	10,177	14	9,659	13	9,611	13
Natural gas (Mcf)	220,977	48	219,552	49	218,044	48	218,601	49	219,302	49
Total boe per day	76,691		74,568		74,953		73,973		74,693	

The increase in the fourth quarter 2011 average daily production compared to the third quarter of 2011 is mainly attributable to production growth in the Swan Hills and Groundbirch areas as a result of our continued capital reinvestment program, and the recovery of development projects and base production after the extreme weather and pipeline outages in the second and third quarters.

Execution of Pengrowth s 2012 capital program is expected to generate full year average production of between 74,500 and 76,500 boe per day, an increase of approximately two percent from our full year 2011 average production of 73,973 boe per day. Pengrowth s average production estimate for 2012 excludes any production associated with the Lindbergh pilot project. Additional volumes from Lindbergh are anticipated in 2013 pending a successful pilot project.

Light Oil

Fourth quarter 2011 light oil production increased eight percent from the third quarter of 2011. This increase is mainly attributable to higher sales volumes at Judy Creek primarily due to new wells. In addition, volumes recovered from extreme weather and third party pipeline outages that occurred in the second and third quarters of 2011.

Table of Contents

Light oil production increased five percent in the fourth quarter of 2011 compared to the same quarter last year due to production from new wells in the Swan Hills area partially offset by natural decline. For the full year 2011 oil volumes were down one percent compared to the full year 2010 as reduced volumes in 2011 due to extreme weather, forest fires and unscheduled pipeline outages were mostly offset by new wells and optimization in the Swan Hills area.

Heavy Oil

Heavy oil production increased one percent in the fourth quarter of 2011 compared to the third quarter of 2011 as increased production at East Bodo and successful optimization activities in Jenner were mostly offset by reductions at Tangleflags due to surface and sub-surface maintenance work.

The three percent decrease between the fourth quarters of 2011 and 2010 and the five percent decrease year-over-year are attributable to increased maintenance activities and natural declines partially offset by the previously mentioned production gains in East Bodo and Jenner.

NGLs

NGL production was essentially unchanged in the fourth quarter of 2011 compared to the third quarter of 2011.

Volumes increased three percent in the fourth quarter of 2011 versus the same period last year due to additional production in Carson Creek and from the Olds Elkton development program. NGL production remained unchanged for the full year 2011 compared to 2010 as the previously mentioned increases at Carson Creek and Olds were offset by turnaround activities in Harmattan, one less condensate shipment at Sable Offshore Energy Project (SOEP) and normal declines.

Natural Gas

Fourth quarter natural gas production remained relatively unchanged compared to the third quarter of 2011 as new production at Groundbirch was offset by turnaround activities in the Harmattan area.

Gas production increased one percent in the fourth quarter of 2011 compared to the same period in 2010 and remained steady year-over-year. Increased gas production from Groundbirch and the Olds Elkton development program was offset by planned maintenance shutdowns and natural declines.

COMMODITY PRICES

Average Realized Prices

	Three months ended			Twelve months ended	
(Cdn$ unless otherwise indicated)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Light oil (per bbl) (1)	95.19	89.61	78.52	92.55	76.07
after realized commodity risk management (1)	91.58	91.95	76.13	89.94	76.22
Heavy oil (per bbl)	76.13	62.36	60.42	68.24	60.22
Natural gas liquids (per bbl)	70.54	66.58	56.74	69.31	56.99
Natural gas (per Mcf)	3.26	3.57	3.68	3.61	4.08
after realized commodity risk management	3.77	4.05	4.87	4.08	5.00
Total per boe (1)	53.88	50.61	46.58	52.50	46.93
after realized commodity risk management (1)	54.28	52.68	49.34	53.13	49.68
Other production income (1)	0.89	0.81	0.67	0.71	0.52
Total oil and gas sales per boe (1)	55.17	53.49	50.01	53.84	50.20
Average Benchmark prices					
WTI oil (U.S.$ per bbl)	94.06	89.54	85.24	95.11	79.61
AECO spot gas (Cdn$ per MMBtu)	3.19	3.66	3.61	3.63	3.99
NYMEX gas (U.S.$ per MMBtu)	3.48	4.05	3.98	4.03	4.38

Currency exchange rate ($ Cdn = $1 U.S.)	0.98	1.02	0.99	1.01	0.97

(1) Prior periods restated to conform to presentation in the current period.

Table of Contents

For the full year 2011, WTI benchmark crude oil prices increased 19 percent from 2010, averaging U.S. $95.11 per barrel compared to an average price of U.S. $79.61 per barrel in 2010. 2011 fourth quarter benchmark crude prices increased five percent from an average price of U.S. $89.54 per bbl in the third quarter 2011 and 10 percent from an average price of U.S. $85.24 in the fourth quarter 2010. Pengrowth s average realized price for light oil, after risk management activities, averaged Cdn $89.94 per barrel in 2011 compared to Cdn $76.22 in 2010, an 18 percent increase. Fourth quarter 2011 realized prices were essentially unchanged from the third quarter 2011, primarily due to lower realized commodity risk management activities. Compared to the same quarter last year, fourth quarter 2011 realized prices were 21 percent higher primarily due to higher benchmark prices.

Natural gas markets continued their downward trend in 2011 as mild weather combined with oversupply issues largely attributable to increased production from shale gas plays more than offset demand. The U.S. based NYMEX natural gas benchmark averaged U.S. $4.03 per MMBtu in 2011, an eight percent decline from 2010 average prices of U.S. $4.38 per MMBtu. Fourth quarter 2011 benchmark prices decreased 14 percent from an average price of U.S. $4.05 per MMBtu in the third quarter 2011 and 13 percent from an average price of U.S. $3.98 per MMBtu in the fourth quarter 2010.

AECO spot prices continued to trade at a discount to the NYMEX benchmark, although the gap narrowed throughout the year. AECO spot prices declined nine percent year over year to an average price of Cdn $3.63 per MMBtu in 2011 from Cdn $3.99 per MMBtu in 2010. Fourth quarter 2011 prices decreased approximately 13 percent from the third quarter 2011 average price of Cdn $3.66 per MMBtu and 12 percent from the fourth quarter 2010 average price of Cdn $3.61 per MMBtu.

Pengrowth s average realized natural gas price after risk management activities was Cdn $4.08 per Mcf in 2011, an 18 percent decline compared to the 2010 average realized price of Cdn $5.00 per Mcf. Fourth quarter 2011 prices declined seven percent and 23 percent when compared to third quarter 2011 and fourth quarter 2010 average realized prices of Cdn $4.05 per Mcf and Cdn $4.87 per Mcf. The decline in average realized prices quarter over quarter is mainly attributable to the decline in the benchmark prices partially offset by risk management activities. On a year over year basis, realized prices were also lower due to a lower contribution from realized gas commodity risk management activities in 2011.

Pengrowth s full year total average realized price, after risk management activities was Cdn $53.13 per boe in 2011, an approximate seven percent increase over the 2010 average of Cdn $49.68 per boe. This increase is primarily a result of higher benchmark prices for crude oil partially offset by lower natural gas prices and lower contribution from gas commodity risk contracts. Total average realized price of Cdn $54.28 per boe in the fourth quarter of 2011 was three percent higher than Cdn $52.68 per boe in the third quarter of 2011 and 10 percent higher than the average realized price of Cdn $49.34 per boe in the fourth quarter 2010. The higher realized price compared to the third quarter 2011 was primarily due to higher crude oil benchmark prices partially offset by weaker benchmark natural gas prices. Compared to the same quarter last year, realized prices in the fourth quarter of 2011 were higher due to stronger benchmark prices for crude oil, partially offset by a lower contribution from realized gas commodity risk management activities in 2011.

Commodity Risk Management Gains (Losses)

	Three months ended			Twelve months ended	
	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Realized					
Light oil ($ millions)	(7.6)	4.6	(4.8)	(20.4)	1.2
Light oil ($ per bbl)	(3.61)	2.34	(2.39)	(2.61)	0.15
Natural gas ($ millions)	10.4	9.6	23.9	37.3	73.9
Natural gas ($ per Mcf)	0.51	0.48	1.19	0.47	0.92
Combined ($ millions)	2.8	14.2	19.1	16.9	75.1
Combined ($ per boe)	0.40	2.07	2.76	0.63	2.75
Unrealized					
Total unrealized risk management (liabilities) assets at period end ($ millions)	(42.0)	60.8	(2.1)	(42.0)	(2.1)
Less: Unrealized risk management assets (liabilities) at beginning of period ($ millions)	60.8	2.7	50.4	(2.1)	(9.0)
Unrealized (loss) gain on risk management contracts	(102.8)	58.1	(52.5)	(39.9)	6.9

Table of Contents

As part of the risk management strategy, Pengrowth uses forward price swaps to manage exposure to commodity price fluctuations and provide a measure of stability to cash flow.

A $7.6 million realized risk management loss in the fourth quarter of 2011 from crude oil risk management activities, compared to a $4.6 million gain in the third quarter of 2011 was due to benchmark oil prices in the quarter rising higher than the average price achieved through our commodity risk management activities. The $20.4 million realized risk management loss for the year, compared to a $1.2 million gain in 2010 was due to benchmark crude oil prices exceeding our average fixed contracted oil price in 2011.

Realized gains from natural gas commodity risk management activities decreased to $37.3 million for the year ending 2011 compared to $73.9 million for the same period last year; as the 2011 gas fixed contracted price and volumes were lower than in 2010. These factors also contributed to the lower natural gas realized risk management gain of $10.4 million in the fourth quarter 2011 compared to $23.9 million for the same period last year.

The change in fair value of the forward contracts between periods affects net income through the unrealized amounts recorded during the period. The fair value of forward contracts is determined by comparing the contracted fixed price to the forward price curve at each period end. A $102.8 million unrealized loss in the fourth quarter of 2011 compared to a $58.1 million gain in the third quarter of 2011 was due to an increase in the forward price curve for crude oil at period end December 31, 2011 from September 30, 2011 coupled with additional oil risk management contracts entered into during the fourth quarter. A $39.9 million unrealized loss at December 31, 2011, compared to a $6.9 million gain at December 31, 2010, is due to an increase in the forward price curve for crude oil, as well significantly lower risk managed gas volumes at lower contracted prices as at December 31, 2011 as compared to December 31, 2010.

As of December 31, 2011, the following commodity risk management contracts were in place:

Crude Oil:

Reference Point	Volume (bbl/d)	Term	Price per bbl		
Financial:					
WTI [1]	17,000	Jan 1, 2012 - Dec 31, 2012	$	93.23	Cdn
WTI [1]	3,500	Jan 1, 2013 - Dec 31, 2013	$	95.29	Cdn

(1) Associated Cdn $/U.S. $ foreign exchange rate has been fixed.

Natural Gas:

Reference Point	Volume (MMBtu/d)	Term	Price per MMbtu		
Financial:					
AECO	14,217	Jan 1, 2012 - Dec 31, 2012	$	4.45	Cdn

Power:

Reference Point	Volume (MW)	Term	Price per MW		
Financial:					
AESO	15	Jan 1, 2012 - Dec 31, 2012	$	72.83	Cdn
AESO	5	Jan 1, 2013 - Dec 31, 2013	$	74.50	Cdn

Based on our 2012 production forecast, the above contracts represent approximately 65 percent of estimated total oil volumes at an average price of $93.23 per bbl and approximately nine percent of estimated natural gas volumes at $4.45 per MMBtu. The power contracts represent approximately 15 percent of estimated 2012 consumption.

Each Cdn $1 per barrel change in future oil prices results in approximately $7.5 million pre-tax change in the value of the crude contracts, while each Cdn $0.25 per MMBtu change in future natural gas prices results in approximately $1.3 million pre-tax change in the value of the natural gas contracts. The changes in the fair value of the forward contracts directly affects reported net income through the unrealized amounts recorded in the Statement of Income during the period. The effect on cash flow will be recognized separately only upon settlement of the contracts, which could vary significantly from the unrealized amount recorded due to timing and prices when each contract is settled.

Table of Contents

If each contract were to settle at the contract price in effect at December 31, 2011, future revenue and cash flow would be $42.0 million lower than if the contracts were not in place based on the estimated fair value of the risk management liability at period end. The $42.0 million liability is composed of a net liability of $38.6 million relating to contracts expiring within one year and a net liability of $3.4 million relating to contracts expiring beyond one year. Pengrowth currently fixes the Canadian dollar exchange rate at the same time it swaps U.S. dollar denominated commodity in order to protect against changes in the foreign exchange rate.

Each Cdn $1 per MW change in future power prices would result in approximately $0.2 million pre-tax change in the fair value of the risk management contracts.

Pengrowth has not designated any outstanding commodity contracts as hedges for accounting purposes and therefore records these contracts on the Balance Sheet at their fair value and recognizes changes in fair value on the Statement of Income as unrealized commodity risk management gains or losses. There will continue to be volatility in earnings to the extent that the fair value of commodity contracts fluctuate, however these non-cash amounts do not impact Pengrowth s operating cash flow. Realized commodity risk management gains or losses are recorded in oil and gas sales on the Statement Income and impacts cash flow at that time.

In accordance with policies approved by the Board of Directors, Pengrowth may sell forward its production by product volume or power consumption as follows:

Percent of Monthly Interest Production or estimated Power Consumption	Forward Period
Up to 65%	1 - 12 Months
Up to 45%	13 - 24 Months
Up to 30%	25 - 36 Months

Each commodity risk management transaction for natural gas or crude oil shall not exceed 20,000 MMBtu per day and 2,500 bbls per day respectively. Each power consumption risk management transaction shall not exceed 25 MW.

OIL AND GAS SALES

Contribution Analysis

The following table shows the contribution of each product category to the overall sales revenue inclusive of realized commodity risk management activities

($ millions except percentages)	Three months ended						Twelve months ended			
Sales Revenue	Dec 31, 2011	% of total	Sept 30, 2011	% of total	Dec 31, 2010	% of total	Dec 31, 2011	% of total	Dec 31, 2010	% of total
Light oil [(1)]	193.2	49	179.1	49	152.4	44	704.3	49	604.9	44
Heavy oil	45.2	12	36.6	10	37.1	11	160.0	11	149.2	11
Natural gas liquids	68.0	17	63.9	17	53.1	15	244.4	17	199.9	15
Natural gas	76.5	20	81.8	22	97.6	29	325.9	22	400.4	29
Brokered sales/sulphur [(1)]	6.3	2	5.5	1	4.7	1	19.1	1	14.3	1
Total oil and gas sales [(1)]	389.2		366.9		344.9		1,453.7		1,368.7	

(1) Prior period restated to conform to presentation in the current period.

Table of Contents

Price and Volume Analysis

The following table illustrates the effect of changes in prices and volumes on the components of oil and gas sales including the impact of realized commodity risk management activities, for the fourth quarter of 2011 compared to the fourth quarter of 2010. The increased commodity prices realized for liquids after commodity risk management activities during the fourth quarter of 2011 are the primary reason for higher oil and gas sales.

($ millions)	Light oil [(1)]	Natural gas	NGLs	Heavy oil	Other [(1)(2)]	Total [(1)]
Quarter ended December 31, 2010	152.4	97.6	53.1	37.1	4.7	344.9
Effect of change in product prices	35.2	(8.6)	13.3	9.3		49.2
Effect of change in realized commodity risk management activities	(2.8)	(13.5)				(16.3)
Effect of change in sales volumes	8.5	1.0	1.6	(1.3)		9.8
Other	(0.1)			0.1	1.6	1.6
Quarter ended December 31, 2011	193.2	76.5	68.0	45.2	6.3	389.2

(1) Prior period restated to conform to presentation in the current period.

(2) Primarily sulphur sales

The following table illustrates the effect of changes in prices and volumes on the components of oil and gas sales including the impact of realized commodity risk management activity, for the full year of 2011 compared to the same period of 2010. The increased commodity prices realized for liquids during the full year of 2011 have more than offset the impact of lower production volumes, reduced gains from commodity risk management activities and lower realized prices for natural gas.

($ millions)	Light oil [(1)]	Natural gas	NGLs	Heavy oil	Other [(1)(2)]	Total [(1)]
Twelve month period ended December 31, 2010	604.9	400.4	199.9	149.2	14.3	1,368.7
Effect of change in product prices	129.1	(37.0)	43.5	18.8		154.4
Effect of change in realized commodity risk management activities	(21.6)	(36.6)				(58.2)
Effect of change in sales volumes	(8.0)	(1.0)	1.0	(8.0)		(16.0)
Other	(0.1)	0.1			4.8	4.8
Twelve month period ended December 31, 2011	704.3	325.9	244.4	160.0	19.1	1,453.7

(1) Prior period restated to conform to presentation in the current period.

(2) Primarily sulphur sales

ROYALTY EXPENSE

	Three months ended			Twelve months ended	
($ millions except per boe amounts)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Royalty expense	72.3	73.1	60.9	277.9	252.7
$ per boe	10.25	10.65	8.83	10.29	9.27
Royalties as a percent of sales [(1)]	18.6%	19.9%	17.7%	19.1%	18.5%

Royalties as a percent of sales excluding realized risk management contracts [1]	18.7%	20.7%	18.7%	19.3%	19.5%

(1) Prior period restated to conform to presentation in the current period.

Royalties include Crown, freehold, overriding royalties and mineral taxes. Royalty payments are based on revenue before commodity risk management activities; however gains or losses from realized commodity risk management activities are reported as part of revenue and therefore affect royalty rates as a percentage of sales. Fourth quarter royalty rates decreased compared to the third quarter of 2011 due to prior period royalty credits and gas cost allowance claims. The higher royalty rate in the fourth quarter of 2011 compared to the same period last year is due to higher gas cost allowance claims in the fourth quarter of 2010. On a year-over-year basis, royalties as a percentage of sales are higher in 2011 as the percentage of sales revenues from light oil and natural gas liquids have increased resulting in a higher overall royalty rate.

Table of Contents

Royalty expense for 2012 is forecasted to be approximately 20 percent of Pengrowth s sales excluding the impact of risk management contracts.

OPERATING EXPENSES

	Three months ended			Twelve months ended	
($ millions except per boe amounts)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Operating expenses (1)	99.7	99.5	104.9	382.0	357.2
$ per boe	14.13	14.51	15.21	14.15	13.10

(1) Prior period restated to conform to presentation in the current period.

Operating expenses in the fourth quarter of 2011 were relatively unchanged from the third quarter of 2011 however, decreased two percent on a per boe basis. Fourth quarter operating cost savings, primarily in well servicing and general maintenance offset a slight increase in power costs quarter-over-quarter. Subsurface activity and lease and right-of-way maintenance in the fourth quarter of 2011 were significantly down from the same period in 2010 and more than offset the impact of higher power costs when comparing the same two periods.

For the full year of 2011 compared to 2010, operating expenses increased seven percent. Increased expenses were primarily attributable to significantly higher power prices, which represented two-thirds of the year-over-year increase. In addition, increased subsurface maintenance and optimization, increased road, lease and right-of-way maintenance attributable to flooding and extreme wet weather conditions and increased turnaround activity also contributed to higher operating costs in 2011.

2012 operating expenses are forecast to be $384 million or $13.89 per boe. Power costs are approximately 20 percent of Pengrowth s operating costs and will continue to be actively managed through optimizing power usage and risk management programs.

TRANSPORTATION COSTS

	Three months ended			Twelve months ended	
($ millions except per bbl and per Mcf amounts)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Oil transportation (1)	3.7	6.3	4.1	18.4	16.6
$ per bbl	1.75	3.25	2.07	2.34	2.09
Natural gas transportation	1.7	1.8	2.4	7.1	8.5
$ per Mcf	0.09	0.09	0.12	0.09	0.11
NGL transportation	0.2			0.2	
$ per bbl	0.20			0.05	

(1) Prior period restated to conform to presentation in the current period.

Oil transportation decreased approximately 41 percent in the fourth quarter of 2011 compared to the third quarter of 2011 primarily due to a decrease in Pengrowth s clean product trucking costs as the Rainbow Pipeline, which experienced an unscheduled interruption in May 2011, resumed shipping in September 2011. Overall transportation costs increased two percent year-over-year as higher clean product trucking costs were mostly offset by reduced natural gas transportation, primarily due to renegotiated rates.

Pengrowth incurs transportation costs for its natural gas production once the product enters a pipeline at a title transfer point. Pengrowth has the option to sell some of its natural gas directly to markets outside of Alberta by incurring additional transportation costs. Pengrowth sells most of its natural gas without incurring significant additional transportation costs. Pengrowth also incurs transportation costs on its oil and NGL production that includes clean oil trucking charges and pipeline costs up to the custody transfer point. Pengrowth has elected to sell approximately 75 percent of its crude oil at market points beyond the wellhead incurring transportation costs to the first major trading point. The transportation cost is dependent upon third party rates and distance the product travels on the pipeline prior to changing ownership or custody.

Table of Contents

OPERATING NETBACKS

There is no standardized measure of operating netbacks and therefore operating netbacks, as presented below, may not be comparable to similar measures presented by other companies. Pengrowth s operating netbacks have been calculated by taking GAAP balances directly from the Statement of Income and dividing by production. Certain assumptions have been made in allocating operating expenses, other income and royalty injection credits between light oil, heavy oil, natural gas and NGL production.

Pengrowth realized an average operating netback of $29.99 per boe in the fourth quarter of 2011 compared to $27.15 per boe in the third quarter of 2011 and $25.02 per boe for the fourth quarter of 2010. The increase in the netback in the fourth quarter of 2011 compared to the third quarter of 2011 is primarily due to higher NGL and heavy oil commodity prices. Operating netback for the full year of 2011 is higher than the same period of 2010 as a result of higher liquids commodity prices partially offset by higher operating and royalty expenses, and lower natural gas prices.

The sales price used in the calculation of operating netbacks is after realized commodity risk management gains or losses.

	Three months ended			Twelve months ended	
Combined Netbacks ($ per boe)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Oil & gas sales [1]	55.17	53.49	50.01	53.84	50.20
Royalties	(10.25)	(10.65)	(8.83)	(10.29)	(9.27)
Operating expenses	(14.13)	(14.51)	(15.21)	(14.15)	(13.09)
Transportation costs [1]	(0.80)	(1.18)	(0.95)	(0.95)	(0.92)
Operating netback [1]	29.99	27.15	25.02	28.45	26.92

	Three months ended			Twelve months ended	
Light Oil Netbacks ($ per bbl)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Oil & gas sales [1]	92.49	92.89	76.83	90.75	76.83
Royalties	(21.29)	(20.46)	(17.32)	(20.37)	(17.32)
Operating expenses [1]	(15.40)	(17.78)	(18.22)	(16.26)	(15.91)
Transportation costs [1]	(1.75)	(3.25)	(2.07)	(2.36)	(2.10)
Operating netback [1]	54.05	51.40	39.23	51.76	41.50

	Three months ended			Twelve months ended	
Heavy Oil Netbacks ($ per bbl)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Oil & gas sales [1]	76.13	62.36	60.42	68.24	60.22
Royalties	(13.65)	(14.23)	(11.25)	(13.81)	(11.84)
Operating expenses [1]	(13.91)	(15.54)	(16.23)	(14.45)	(15.76)
Operating netback	48.57	32.59	32.94	39.98	32.62

	Three months ended			Twelve months ended	
NGLs Netbacks ($ per bbl)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Oil & gas sales	70.54	66.58	56.74	69.31	56.99
Royalties	(14.51)	(19.42)	(13.97)	(16.92)	(14.80)
Operating expenses	(12.34)	(17.03)	(13.56)	(14.65)	(12.17)
Transportation costs	(0.20)			(0.05)	
Operating netback	43.49	30.13	29.21	37.69	30.02

	Three months ended			Twelve months ended	

Natural Gas Netbacks ($ per Mcf)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Oil & gas sales [(1)]	3.98	4.22	5.03	4.24	5.12
Royalties	(0.26)	(0.31)	(0.31)	(0.33)	(0.42)
Operating expenses [(1)]	(2.31)	(1.98)	(2.28)	(2.11)	(1.89)
Transportation costs	(0.09)	(0.09)	(0.12)	(0.09)	(0.11)
Operating netback	1.32	1.84	2.32	1.71	2.70

(1) Prior period restated to conform to presentation in the current period.

Table of Contents

GENERAL AND ADMINISTRATIVE EXPENSES

	Three months ended			Twelve months ended	
($ millions except per boe amounts)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Cash G&A expense	16.3	14.5	12.1	64.3	46.3
$ per boe	2.31	2.11	1.76	2.38	1.70
Non-cash G&A expense	2.0	2.4	(1.0)	11.0	4.6
$ per boe	0.28	0.35	(0.16)	0.41	0.17
Total G&A	18.3	16.9	11.1	75.3	50.9
$ per boe	2.60	2.46	1.61	2.79	1.87

Fourth quarter cash G&A expenses are higher when compared to the third quarter mainly due to increased information technology (IT) costs and professional services. Cash G&A expenses for 2011 include certain costs relating to IT, office facilities and operations support previously charged to operating expenses in 2010. The impact of this change for the fourth quarter and the full year of 2011 is approximately $2.3 million and approximately $12.7 million, respectively. In addition, severance costs, performance bonus true-up and non-recurring items contribute to higher cash G&A expenses in 2011 when compared to 2010.

The non-cash component of G&A represents the compensation expense associated with Pengrowth s Long Term Incentive Plans (LTIP) (see Note 14 to the financial statements). The compensation costs associated with these plans are expensed over the applicable vesting period. The $6.4 million increase in the 2011 non-cash G&A as compared to 2010 was primarily due to the higher expense calculation for the new LTIP. Also contributing was a higher performance multiplier of 0.5 applicable to the Deferred Entitlement Share Units (DESU) in 2011 as compared to a zero performance multiplier booked in 2010 applicable to the DESUs that vested in 2011.

Total G&A costs are expected to decrease for 2012 to $2.68 per boe when compared to the full year 2011 of $2.79 per boe. Included in Pengrowth s 2012 G&A forecast are non-cash G&A costs of approximately $0.49 per boe compared to $0.41 per boe in 2011.

DEPLETION, DEPRECIATION, AMORTIZATION AND ACCRETION

	Three months ended			Twelve months ended	
($ millions except per boe amounts)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Depletion, depreciation and amortization	117.6	112.8	108.2	437.9	432.4
$ per boe	16.67	16.44	15.69	16.22	15.86
Accretion	4.0	3.9	4.0	15.6	17.7
$ per boe	0.57	0.57	0.58	0.58	0.65

Depletion and depreciation of property, plant and equipment is calculated using the unit of production method based on proved plus probable reserves and is based on the dollar value of the property, plant and equipment asset base. Depletion expense in the fourth quarter of 2011 compared to the third quarter of 2011 reflects a higher depletion cost as a result of increased production offset by positive reserve revisions booked in the fourth quarter. Depletion expense in the fourth quarter and for the year ended 2011 compared to the same periods last year were higher due mainly to the impact of the increased capital program in 2011 as compared to 2010 and higher costs associated with horizontal drilling and multi-stage frac completions for wells drilled in the year.

Accretion is a charge to earnings that increases the Asset Retirement Obligations (ARO) liability for the passage of time (unwinding of the discount). Accretion is charged to net income over the lifetime of the producing oil and gas assets. Accretion has remained relatively stable compared to the third quarter of 2011. Accretion has decreased year over year due a reduction in the discount rates late in 2010 with further reduction in the third and fourth quarters of 2011.

IMPAIRMENT

In the fourth quarter of 2011, Pengrowth recognized a $27.4 million pre-tax impairment charge on the producing portion of the Groundbirch CGU as the carrying value exceeded the fair value on December 31, 2011. Fair value was determined based on the total proved plus probable reserves estimated by Pengrowth s independent reserves evaluator using the period end commodity price forecast of Pengrowth s independent reserves evaluator and discounted at a market rate.

Table of Contents

This impairment charge resulted from a low natural gas price forecast by Pengrowth s independent reserves evaluator and allocation of 2012 capital to properties with better economic returns. As a result, goodwill attributed to the Groundbirch CGU was reduced by $16.3 million to $Nil and the PP&E was reduced by $11.1 million. See Note 6 to the financial statements for detailed disclosure of the assumptions used to determine the fair value and the sensitivity of these assumptions on the impairment recognized.

INTEREST AND FINANCING CHARGES

	Three months ended			Twelve months ended	
($ millions)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Interest and Financing charges	21.1	19.3	19.6	75.9	70.5

At December 31, 2011, Pengrowth had $1 billion in long term debt. The majority of long term debt consists of U.S. dollar denominated fixed rate notes at a weighted average interest rate of 6.3 percent. Pengrowth has an undrawn syndicated bank facility which is subject to prevailing market rates.

Pengrowth renewed the syndicated bank facility in the fourth quarter which extended the facility to a four year term due November 29, 2015. As a result, the amount of capitalized renewal fees on the previous 2010 bank renewal were expensed in the fourth quarter which led to the increased interest and financing fees in 2011.

The fees charged under the previous syndicated credit facility increased upon its renewal in the fourth quarter of 2010 when rates were reset. The higher fees combined with higher debt levels as a result of greater capital spending in 2011 resulted in higher interest and financing charges year over year. In addition, 2011 interest and financing charges include the amount expensed for the capitalized fees on the previous syndicated credit facility as noted above.

GAIN ON INVESTMENTS

Pengrowth owns 1.0 million shares of a private corporation with an estimated fair value of $35 million. The fair value of these shares has increased to $35 million as at December 31, 2011 resulting in an unrealized gain of $23 million in the fourth quarter of 2011. The fair value is based on the most recent private placement equity offering closed by the private company. See Note 5 to the financial statements for additional information.

TAXES

Deferred income tax is a non-cash item relating to temporary differences between the accounting and tax basis of Pengrowth s assets and liabilities and has no immediate impact on Pengrowth s cash flows. During the year ended December 31, 2011, Pengrowth recorded deferred tax expense of $22.3 million (December 31, 2010 $171.3 million). No current income taxes were paid by Pengrowth in 2011 and 2010. See Note 12 to the financial statements for additional information.

FOREIGN CURRENCY GAINS & LOSSES

	Three months ended			Twelve months ended	
($ millions)	Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Dec 31, 2011	Dec 31, 2010
Unrealized foreign exchange gain (loss) on U.S. dollar denominated debt	28.8	(75.5)	31.0	(19.5)	50.7
Unrealized foreign exchange gain (loss) on U.K. pound sterling denominated debt	2.8	(4.3)	3.3	(1.4)	7.4
	31.6	(79.8)	34.3	(20.9)	58.1
Unrealized (loss) gain on foreign exchange risk management contract on U.K. pound sterling denominated debt	(2.4)	3.4	(4.5)	1.8	(8.1)
	29.2	(76.4)	29.7	(19.1)	49.9

Total Unrealized foreign exchange gain (loss)					
Realized foreign exchange (loss) gain	(0.6)	(0.8)		(1.6)	(2.1)

Pengrowth s unrealized foreign exchange gains and losses are primarily attributable to the translation of the foreign denominated long term debt. The gains or losses are calculated by comparing the translated Canadian dollar balance of foreign denominated long term debt from one period to another. The total unrealized foreign exchange gain in the fourth quarter was $29.2 million compared to an unrealized foreign exchange loss of $76.4 million and a gain of $29.7 million in the third quarter of 2011 and fourth quarter of 2010, respectively. The unrealized foreign exchange gain this quarter compared to the loss in the third quarter was mainly the result of an increase in the closing exchange rate of the Canadian dollar to U.S. dollar since September 2011. The total unrealized foreign exchange loss as at December 31, 2011 was $19.1 million, compared to an unrealized gain of $49.9 million as at December 31, 2010. The unrealized loss this year compared to the gain in the prior year was mainly the result of a decrease in the closing exchange rate of the Canadian dollar to U.S. dollar since 2010.

As some realized commodity prices are derived from U.S. denominated benchmarks, a weaker U.S. dollar negatively impacts oil and gas revenues. To mitigate this, Pengrowth elects to hold a portion of its long term debt in U.S. dollars as a natural hedge. Therefore, a decline in revenues as a result of foreign exchange fluctuations will be partially offset by a reduction in U.S. dollar interest expense.

ASSET RETIREMENT OBLIGATIONS

($ millions)	Dec 31, 2011	Dec 31, 2010	Change
ARO, opening balance	447.1	450.6	(3.5)
Revisions due to discount rate changes	206.6	90.9	115.7
Expenditures on remediation	(21.9)	(20.9)	(1.0)
Accretion and Other [(1)]	29.1	(73.5)	102.6
ARO, closing balance	660.9	447.1	213.8

(1) 2010 includes revision for inflation.

The total future ARO is based on management s estimate of costs to remediate, reclaim and abandon wells and facilities having regard for Pengrowth s working interest and the estimated timing of the costs to be incurred in future periods. Pengrowth has developed an internal process to calculate these estimates which considers applicable regulations, actual and anticipated costs, type and size of well or facility and the geographic location.

For the year ended December 31, 2011, Pengrowth s ARO liability increased by $213.8 million. The increase is mainly due to the ARO discount rate being revised from three and one half percent per annum in the first six months of 2011 to three percent per annum in the third quarter, and then to two and one half percent per annum in the fourth quarter to reflect changes to the underlying risk free long term Government of Canada bond yield.

Pengrowth has estimated the net present value of its total ARO to be $660.9 million as at December 31, 2011 (December 31, 2010 $447.1 million), based on a total escalated future liability of $1.8 billion (December 31, 2010 $1.8 billion). These costs are expected to be incurred over 65 years with the majority of the costs incurred between 2036 and 2077. A risk free rate of two and one half percent per annum and an inflation rate of one and one half percent were used to calculate the net present value of the ARO.

REMEDIATION TRUST FUNDS AND REMEDIATION AND ABANDONMENT EXPENSE

During 2011, Pengrowth s contributions were $7.1 million (December 31, 2010 $7.6 million), into trust funds established to fund certain abandonment and reclamation costs associated with Judy Creek and SOEP. The total balance of the remediation trust funds was $49.7 million at December 31, 2011 (December 31, 2010 $42.1 million).

Every five years Pengrowth must evaluate the value of the assets in the Judy Creek remediation trust fund and the outstanding ARO, and make recommendations to the former owner of the Judy Creek properties as to whether contribution levels should be changed. The next evaluation is anticipated to occur in 2012. Contributions to the Judy Creek remediation trust fund may change based on future evaluations of the fund.

As a working interest holder in SOEP, Pengrowth is under a contractual obligation to contribute to a remediation trust fund. The funding levels are based on the raw gas delivered and processed at the various facilities; funding levels for this fund may change each year pending a review by the owners.

Pengrowth takes a proactive approach to managing its well abandonment and site restoration obligations. There is an on-going program to abandon wells and reclaim well and facility sites. Through December 31, 2011, Pengrowth spent $21.9 million on abandonment and reclamation (December 31, 2010 $20.9 million). Pengrowth expects to spend approximately $18.5 million in 2012 on reclamation and abandonment, excluding contributions to remediation trust funds and orphan well levies from the Alberta Energy Resources Conservation Board.

Table of Contents

CLIMATE CHANGE PROGRAMS

Since becoming effective July 1, 2007, Alberta regulates Greenhouse Gas (GHG) emissions under the *Climate Change and Emissions Management Act*, the *Specified Gas Reporting Regulation* (the SGRR), which imposes GHG emissions reporting requirements, and the *Specified Gas Emitters Regulation* (the SGER) which imposes GHG emissions limits. These regulations require Alberta facilities that emit more than 100,000 tonnes of greenhouse gases a year to reduce emissions intensity by 12 percent over the average baseline emission levels of 2003, 2004 and 2005. Companies can make their reductions through improvements to their operations; by purchasing Alberta-based offset credits or by contributing to the Climate Change and Emissions Management Fund. Pengrowth in 2011 operated two facilities that are subject to the Alberta climate change regulations where a 12 percent reduction from the baseline is required. Collectively, these facilities have reduced emissions by approximately 34 percent exceeding current-day requirements. Further reductions to baseline targets may occur and Pengrowth is assessing options for meeting future changes to greenhouse gas emission requirements. If the emissions remain at the current levels and the baseline is modified, Pengrowth may experience additional annual costs of as much as $0.5 million for the acquisition of credits relating to the facilities. Unutilized credits from one year may be carried forward to future years. For further information, see Pengrowth s AIF. Pengrowth is waiting on additional information from other jurisdictions to assess the impact it will have on its operations.

GOODWILL

In accordance with IFRS, goodwill is tested for impairment at each year end, or when there is an indication of impairment, in conjunction with the assessment of impairment of property, plant and equipment. As at December 31, 2011, Pengrowth recorded goodwill of $700.7 million. Goodwill decreased by $16.3 million in the current year due to an impairment of the producing portion of the Groundbirch property acquired in the Monterey Exploration Ltd. business combination. See Notes 4 and 8 to the financial statements for details. Management has assessed the remaining goodwill for impairment and determined there is no additional impairment at December 31, 2011.

WORKING CAPITAL

The working capital deficiency at December 31, 2011 was $137.3 million, compared to $109.2 million at December 31, 2010.

FINANCIAL RESOURCES AND LIQUIDITY

As at:	Dec 31, 2011	Dec 31, 2010	Change
($ millions)			
Term credit facilities	$	$ 39.0	$ (39.0)
Senior unsecured notes	1,007.7	985.4	22.3
Long term debt	1,007.7	1,024.4	(16.7)
Working capital deficiency	137.3	109.2	28.1
Total debt	$ 1,145.0	$ 1,133.6	$ 11.4

Years Ended	Dec 31 2011	Dec 31 2010	Change
Net income	$ 84.5	$ 149.8	$ (65.3)
Add:			
Interest and financing charges	75.9	70.5	5.4
Deferred tax expense	22.3	171.3	(149.0)
Depletion, depreciation, amortization and accretion	453.5	450.1	3.4
Impairment of assets	27.4		27.4
Other non-cash expenses (income)	34.8	(145.4)	180.2
EBITDA	$ 698.4	$ 696.3	$ 2.1
Total debt to EBITDA	1.6	1.6	
Total Capitalization [1]	$ 4,492.3	$ 4,315.9	$ 176.4
Total debt as a percentage of total capitalization	25.5%	26.3%	

(1) Total capitalization includes total outstanding debt plus Shareholders Equity. Total outstanding debt includes working capital deficit (excess).

Table of Contents

As at December 31, 2011, long term debt decreased by $16.7 million from December 31, 2010. In November 2011, Pengrowth completed an equity offering for net proceeds of $288.1 million which was used primarily to pay down amounts owing on the revolving credit facility as a result of an increased capital program in 2011. The decrease in long term debt was offset by an increase of $21.0 million due to foreign currency translation losses of approximately $19.6 million on the U.S. dollar denominated debt, and $1.4 million on the U.K. pound sterling denominated debt. The decrease in debt resulted in a trailing 12 month Total Debt to EBITDA ratio at December 31, 2011 of 1.6x which is within corporate targets.

Term Credit Facilities

At December 31, 2011, Pengrowth s revolving credit facility was undrawn (December 31, 2010 $39 million) and letters of credit of $24 million (December 31, 2010 $18 million) were outstanding. The credit facility includes a committed value of $1 billion and a $250 million expansion feature providing Pengrowth with up to $1.25 billion of credit capacity from a syndicate of seven Canadian and three foreign banks. The revolving credit facility matures on November 29, 2015 and can be extended at Pengrowth s discretion any time prior to maturity subject to syndicate approval.

Pengrowth also maintains a $50 million demand operating facility with one Canadian bank. As at December 31, 2011, this facility was undrawn (December 31, 2010 $22 million) and $1.5 million (December 31, 2010 $5 million) in outstanding letters of credit were outstanding. When utilized, this facility appears on the Balance Sheet as a current liability in Bank indebtedness.

Together, these two facilities provide Pengrowth with approximately $1,062 million of available credit capacity at December 31, 2011, with the ability to expand the facilities by an additional $250 million.

Financial Covenants

Pengrowth s senior unsecured notes and credit facilities are subject to a number of covenants, all of which were met at all times during the preceding twelve months, and at December 31, 2011. All loan agreements can be found on SEDAR (www.sedar.com) filed under Other or Material Document .

The calculation for each financial covenant is based on specific definitions, is not in accordance with GAAP and cannot be readily replicated by referring to Pengrowth s financial statements. The financial covenants are substantially similar between the credit facilities and the senior unsecured notes.

Key financial covenants are summarized below:

1. Total senior debt must not exceed 3.0 times EBITDA for the last four fiscal quarters;

2. Total debt must not exceed 3.5 times EBITDA for the last four fiscal quarters;

3. Total senior debt (excluding working capital) must be less than 50 percent of total book capitalization; and

4. EBITDA must not be less than four times interest expense.

There may be instances, such as financing an acquisition, where it would be acceptable for total debt to trailing EBITDA to be temporarily offside. In the event of a significant acquisition, certain credit facility financial covenants are relaxed for two fiscal quarters after the close of the acquisition. Pengrowth may prepare pro forma financial statements for debt covenant purposes and has additional flexibility under its debt covenants for a set period of time. This would be a strategic decision recommended by management and approved by the Board of Directors with steps taken in the subsequent period to restore Pengrowth s capital structure based on its capital management objectives.

Failing a financial covenant may result in one or more of Pengrowth s loans being in default. In certain circumstances, being in default of one loan will, absent a cure, result in other loans also being in default. In the event that non-compliance continued, Pengrowth would have to repay, refinance or re-negotiate the terms and conditions of the debt and may have to suspend dividends to shareholders.

If certain financial ratios reach or exceed certain levels, management may consider steps to improve these ratios. These steps may include, but are not limited to, raising equity, property dispositions, reducing capital expenditures or dividends. Details of these measures are included in Note 17 to the December 31, 2011, financial statements.

Dividend Reinvestment Plan

Pengrowth s Dividend Reinvestment Plan (DRIP) entitles shareholders to reinvest cash dividends in additional shares of the Corporation. Under the DRIP, the shares are issued from treasury at a five percent discount to the weighted average closing price of all shares traded on the TSX for the five trading days preceding a dividend payment date.

Table of Contents

During the year ended December 31, 2011, 5.0 million shares were issued for cash proceeds of $54.7 million under the DRIP compared to 2.3 million trust units for cash proceeds of $24.1 million for the same period last year.

On January 3, 2012, Pengrowth announced that it has introduced a Premium Dividend program in addition to the DRIP, effective February 2012.

Pengrowth does not have any off balance sheet financing arrangements.

FINANCIAL INSTRUMENTS

Financial instruments are utilized by Pengrowth to manage its exposure to commodity price fluctuations, foreign currency and interest rate exposures. Pengrowth s policy is not to utilize financial instruments for trading or speculative purposes. Please see Note 2 to the financial statements for a description of the accounting policies for financial instruments and Note 18 to the financial statements for additional information regarding market risk, credit risk, liquidity risk and fair value of Pengrowth s financial instruments.

FUNDS FLOW FROM OPERATIONS AND DIVIDENDS

The following table provides Funds Flow from Operations, net income and dividends declared with the excess (shortfall) over dividends and Payout Ratio:

($ millions, except per share amounts)	Three months ended Dec 31, 2011	Sept 30, 2011	Dec 31, 2010	Twelve months ended Dec 31, 2011	Dec 31, 2010
Funds flow from operations	171.1	150.4	139.9	620.0	626.2
Net (loss) income	(9.0)	(0.5)	(152.0)	84.5	149.8
Dividends declared	73.5	69.2	45.1 (1)	280.2	232.6 (1)
Dividends declared per share	0.21	0.21	0.14 (1)	0.84	0.77 (1)
Excess of funds flow from operations less dividends declared	97.6	81.2	94.8	339.8	393.6
Per Share	0.28	0.25	0.30	1.02	1.31
Shortfall of net (loss) income less dividends declared	(82.5)	(69.7)	(197.1)	(195.7)	(82.8)
Per Share	(0.24)	(0.21)	(0.61)	(0.59)	(0.28)
Payout Ratio	43%	46%	32%	45%	37%

(1) Reflects one month less of distributions declared as a result of the corporate conversion.

As a result of the depleting nature of Pengrowth s oil and gas assets, capital expenditures are required to offset production declines while other capital is required to maintain facilities, acquire prospective lands and prepare future projects. Capital spending and acquisitions may be funded by the excess of Funds Flow from Operations less dividends declared, through additional debt or the issuance of equity. Pengrowth does not deduct capital expenditures when calculating Funds Flow from Operations.

Funds Flow from Operations is derived from producing and selling oil, natural gas and related products. As such, Funds Flow from Operations is highly dependent on commodity prices. Pengrowth enters into forward commodity contracts to mitigate price volatility and to provide a measure of stability to monthly cash flow. Details of commodity contracts are contained in Note 18 to the financial statements.

DIVIDENDS

The board of directors and management regularly review the level of dividends. The board considers a number of factors, including expectations of future commodity prices, capital expenditure requirements, and the availability of debt and equity capital. As a result of the volatility in commodity prices, changes in production levels and capital expenditure requirements, there can be no certainty that Pengrowth will be able to maintain current levels of dividends and dividends can and may fluctuate in the future. Pengrowth has no restrictions on the payment of its dividends other than maintaining its financial covenants in its borrowings.

During 2011, cash dividends were paid to shareholders on the 15th or next business day of the month. Pengrowth paid $0.07 per share in each of the months January through December 2011, for an aggregate cash dividend of $0.84 per share.

Table of Contents

SUMMARY OF QUARTERLY RESULTS

The following table is a summary of quarterly information for 2011 and 2010.

2011	Q1	Q2	Q3	Q4
Oil and gas sales ($ millions) [1]	340.9	356.7	366.9	389.2
Net income (loss) ($ millions)	5.4	88.5	(0.5)	(9.0)
Net income (loss) per share ($)	0.02	0.27		(0.03)
Net income (loss) per share - diluted ($)	0.02	0.27		(0.03)
Funds flow from operations ($ millions)	146.8	151.7	150.4	171.1
Dividends declared ($ millions)	68.6	68.9	69.2	73.5
Dividends declared per share ($)	0.21	0.21	0.21	0.21
Daily production (boe)	73,634	70,958	74,568	76,691
Total production (Mboe)	6,627	6,457	6,860	7,056
Average realized price ($ per boe)	51.15	54.41	52.68	54.28
Operating netback ($ per boe)	27.64	28.97	27.15	29.99
2010	**Q1**	**Q2**	**Q3**	**Q4**
Oil and gas sales ($ millions) [1]	362.7	340.8	320.3	344.9
Net income (loss) ($ millions)	139.0	18.2	144.6	(152.0)
Net income (loss) per share ($)	0.48	0.06	0.49	(0.47)
Net income (loss) per share - diluted ($)	0.48	0.06	0.48	(0.47)
Funds flow from operations ($ millions)	161.5	175.5	149.3	139.9
Dividends declared ($ millions)	61.0	61.2	65.3	45.1[2]
Distributions declared per unit ($)	0.21	0.21	0.21	0.14[2]
Daily production (boe)	75,627	75,517	72,704	74,953
Total production (Mboe)	6,806	6,872	6,689	6,896
Average realized price ($ per boe) [1]	52.79	49.17	47.39	49.34
Operating netback ($ per boe) [1]	28.24	27.75	26.64	25.02

(1) Prior period restated to conform to presentation in the current period.

(2) Reflects one month less of distribution declared as a result of the corporate conversion.

In addition to natural decline, production changes over these quarters was a result of production limitations due to first quarter 2011 unscheduled pipeline outage, second quarter 2011 scheduled maintenance shutdowns and restrictions due to flooding and forest fires and unscheduled maintenance in the third quarter of 2010 partly offset by the Monterey acquisition in the third quarter of 2010. Changes in commodity prices have affected oil and gas sales, which have been partially muted by risk management activity to mitigate price volatility and to provide a measure of stability to monthly cash flow. Quarterly net income (loss) has also been impacted by non-cash charges, in particular depletion, depreciation and amortization, impairment charges, unrealized gains on investments, accretion of ARO, unrealized mark-to-market gains and losses, unrealized foreign exchange gains and losses, and future taxes. Funds flow was also impacted by changes in royalty expense, operating and general and administrative costs.

Table of Contents

Selected Annual Information

The table below provides a summary of selected annual financial information for the years ended 2011, 2010, and 2009.

	Twelve months ended December 31		
($ millions unless otherwise indicated)	2011	2010	2009[2]
Oil and gas sales [1]	1,453.7	1,368.7	1,351.5
Net income [2]	84.5	149.8	84.9
Net income per share [3] ($)	0.25	0.50	0.32
Net income per share [3] diluted ($)	0.25	0.49	0.32
Dividends declared per share ($) [4]	0.84	0.77	1.08
Total assets	5,644.7	5,226.6	4,693.6
Long term debt [5]	1,007.7	1,024.4	982.4
Shareholders equity[3]	3,347.3	3,182.3	2,795.2
Number of shares outstanding at year end (thousands)	360,282	326,024	289,835

(1) Prior period restated to conform to presentation in the current period.

(2) Pengrowth s IFRS transition date was January 1, 2010. 2009 comparative information has not been restated.

(3) Comparative amounts are Trust units and Trust Unitholders equity.

(4) 2010 reflects one month less of distribution declared as a result of the corporate conversion.

(5) Includes long term debt and convertible debentures, as applicable.

COMMITMENTS AND CONTRACTUAL OBLIGATIONS

($ millions)	2012	2013	2014	2015	2016	Thereafter	Total
Long term debt [1]	$	$ 50.9	$	$ 151.7	$	$ 808.8	$ 1,011.4
Interest payments on long term debt [2]	63.1	61.2	60.4	58.0	52.7	70.7	366.1
Other [3]	15.7	15.4	15.0	14.2	14.0	15.9	90.2
	$ 78.8	$ 127.5	$ 75.4	$ 223.9	$ 66.7	$ 895.4	$ 1,467.7
Purchase obligations							
Pipeline transportation	28.5	22.5	19.4	17.5	2.1	0.5	90.5
CO_2 purchases [4]	2.9	2.9	2.9	2.9	0.8		12.4
	$ 31.4	$ 25.4	$ 22.3	$ 20.4	$ 2.9	$ 0.5	$ 102.9
Remediation trust fund payments	0.3	0.3	0.3	0.3	0.3	11.0	12.5
	$ 110.5	$ 153.2	$ 98.0	$ 244.6	$ 69.9	$ 906.9	$ 1,583.1

(1) The debt repayment includes the principal owing at maturity on foreign denominated fixed rate debt translated using the year end exchange rate. (See Note 10 to the financial statements).

(2) Interest payments are calculated at period end exchange rates and interest rates except for foreign denominated fixed rate debt which is calculated at the actual interest rate.

(3) Includes office rent and vehicle leases.

(4) For the Weyburn CO_2 project, prices are denominated in U.S. dollars and have been translated at the year-end exchange rate.

Table of Contents

SUMMARY OF COMMON SHARE TRADING DATA

		High	Low	Close	Volume (000s)	Value ($ millions)
TSX - PGF (Cdn $)						
2011	1st quarter	$ 13.80	$ 11.98	$ 13.41	61,957	795.7
	2nd quarter	$ 13.96	$ 11.56	$ 12.15	39,337	500.2
	3rd quarter	$ 12.84	$ 9.33	$ 9.47	39,079	431.7
	4th quarter	$ 11.18	$ 8.48	$ 10.76	58,503	610.7
	Year	$ 13.96	$ 8.48	$ 10.76	198,876	2,338.4
2010	1st quarter	$ 11.96	$ 10.15	$ 11.75	33,376	372.7
	2nd quarter	$ 12.00	$ 8.50	$ 9.73	34,038	361.0
	3rd quarter	$ 11.44	$ 9.40	$ 11.34	47,522	488.8
	4th quarter	$ 13.38	$ 11.29	$ 12.78	70,469	896.9
	Year	$ 13.38	$ 8.50	$ 12.78	185,405	2,119.4
NYSE - PGH (U.S. $)						
2011	1st quarter	$ 14.14	$ 12.09	$ 13.83	21,853	284.8
	2nd quarter	$ 14.60	$ 11.81	$ 12.58	25,342	332.4
	3rd quarter	$ 13.60	$ 8.94	$ 8.99	31,966	357.3
	4th quarter	$ 11.00	$ 7.99	$ 10.53	25,754	258.1
	Year	$ 14.60	$ 7.99	$ 10.53	104,916	1,232.6
2010	1st quarter	$ 11.78	$ 9.78	$ 11.66	20,473	218.8
	2nd quarter	$ 11.97	$ 7.67	$ 9.16	26,059	268.7
	3rd quarter	$ 11.10	$ 8.85	$ 11.06	20,153	200.0
	4th quarter	$ 13.25	$ 11.02	$ 12.86	19,810	245.0
	Year	$ 13.25	$ 7.67	$ 12.86	86,493	932.5

BUSINESS RISKS

The amount of dividends available to shareholders and the value of Pengrowth common shares are subject to numerous risk factors. Pengrowth s principle source of net cash flow is from Pengrowth s portfolio of producing oil and natural gas properties, the principal risk factors that are associated with the oil and gas business include, but are not limited to, the following influences:

Risks associated with Commodity Prices

The prices of Pengrowth s products (crude oil, natural gas, and NGLs) fluctuate due to many factors including local and global market supply and demand, weather patterns, pipeline transportation, discount for Western Canadian light and heavy oil and natural gas, and political and economic stability.

Production could be shut-in at specific wells or fields in low commodity prices.

Substantial and sustained reductions in commodity prices or equity markets, including Pengrowth s share price, in some circumstances could result in Pengrowth recording an impairment loss as well as affecting the ability to maintain the current dividends, spend capital and meet obligations.

Risks associated with Liquidity

Capital markets may restrict Pengrowth s access to capital and raise its borrowing costs. To the extent that external sources of capital become limited or cost prohibitive, Pengrowth s ability to fund future development and acquisition opportunities may be impaired.

Pengrowth is exposed to third party credit risk through its oil and gas sales, financial hedging transactions and joint venture activities. The failure of any of these counterparties to meet their contractual obligations could adversely impact Pengrowth.

Changing interest rates influence borrowing costs and the availability of capital.

Table of Contents

Failing a financial covenant may result in one or more of Pengrowth s loans being in default. In certain circumstances, being in default of one loan will result in other loans also being in default. In the event that non-compliance continued, Pengrowth would have to repay the debt, refinance the debt or negotiate new terms with the debt holders and may have to suspend dividends to shareholders.

Pengrowth s 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.

Uncertainty in international financial markets concerning could lead to constrained capital markets, increased cost of capital and negative impact on economic activity and commodity prices.

Risks associated with Legislation and Regulatory Changes

Government royalties, income taxes, commodity taxes and other taxes, levies and fees have a significant economic impact on Pengrowth s financial results. Changes to federal and provincial legislation governing such royalties, taxes and fees could have a material impact on Pengrowth s financial results and the value of Pengrowth s common shares.

Environmental laws and regulatory initiatives impact Pengrowth financially and operationally. We may incur substantial capital and operating expenses 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 future regulations to reduce greenhouse gas and other emissions.

Regulations surrounding the fracture stimulation of wells, including increasing disclosure and restrictions, differ and depend on the area of operation. Pengrowth may have to adjust operational practice, increase compliance and incur additional cost as a result.

Changes to accounting policies 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.

Risks associated with Operations

The marketability of our production depends in part upon the availability, proximity and capacity of gathering systems, pipelines and processing facilities. Operational or economic factors may result in the inability to deliver our products to market.

Increased competition for properties could drive the cost of acquisitions up and expected returns from the properties down.

Timing of oil and gas operations is dependent on gaining timely access to lands. Consultations, that are mandated by governing authorities, with all stakeholders (including surface owners, First Nations and all interested parties) are becoming increasingly time consuming and complex, and are having a direct impact on cycle times.

Availability of specialized equipment and goods and services, during periods of increased activity within the oil and gas sector, may adversely impact timing of operations.

Oil and gas operations can be negatively impacted by certain weather conditions, including floods, forest fires and other natural events, which may restrict production and/or delay drilling activities.

A significant portion of Pengrowth s properties are operated by third parties whereby Pengrowth has less control over the pace of capital and operating expenditures. If these operators fail to perform their duties properly, or become insolvent, we may experience interruptions in production and revenues from these properties or incur additional liabilities and expenses as a result of the default of these third party operators.

Geological and operational risks affect the quantity and quality of reserves and the costs of recovering those reserves. Our actual results will vary from our reserve estimates and those variations could be material.

Oil and gas operations carry the risk of damaging the local environment in the event of equipment or operational failure. The cost to remediate any environmental damage could be significant.

Delays in business operations could adversely affect Pengrowth s dividends to shareholders and the market price of the common shares.

During periods of increased activity within the oil and gas sector, the cost of goods and services may increase.

During times of increased activity it may be more difficult to hire and retain staff and the cost for certain skills may increase.

Table of Contents

Attacks by individuals against facilities and the threat of such attacks may have an adverse impact on Pengrowth and the implementation of security measures as a precaution against possible attacks would result in increased cost to Pengrowth s business.

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.

Delays or failure to secure regulatory approvals for Steam Assisted Gravity Drainage (SAGD) projects may result in capital being spent with reduced economics, reduced or no further reserves being booked, and reduced or no associated future production and cash flow.

The performance and results of a SAGD project such as Lindbergh is dependent on the ability of the steam to access the reservoir and efficiently move additional heavy oil that would otherwise remain trapped within the reservoir rock. The amount and cost of steam required, the additional oil recovered, the quality of the oil produced, the ability to recycle produced water into steam and the ability to manage costs will determine the economic viability for a SAGD project.

Risks associated with Strategy

Capital re-investment on our existing assets may not yield the expected benefits and related value creation. Drilling opportunities may prove to be more costly or less productive than anticipated. In addition, the dedication of a larger percentage of our cash flow to such opportunities may reduce the funds available for dividend payment to shareholders. In such an event, the market value of the common shares may be adversely affected.

Pengrowth s oil and gas reserves will be depleted over time and our level of cash flow from operations and the value of our common shares could be reduced if reserves and production are not replaced. The ability to replace production depends on the amount of capital invested and success in developing existing reserves, acquiring new reserves and financing this development and acquisition activity within the context of the capital markets.

Incorrect assessments of value at the time of acquisitions could adversely affect the value of our common shares and dividends to our shareholders.

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.

General Business Risks

Investors interest in the oil and gas sector may change over time which would affect the availability of capital and the value of Pengrowth common shares.

Inflation may result in escalating costs, which could impact dividends and the value of Pengrowth common shares.

Canadian / U.S. exchange rates influence revenues and, to a lesser extent, operating and capital costs. Pengrowth is also exposed to foreign currency fluctuations on the U.S. dollar denominated notes for both interest and principal payments.

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

As the unit of measure is smaller under IFRS, it may lead to more frequent impairments at the individual CGU level as a surplus from one asset will no longer shelter a deficit in another.

Failure to receive regulatory approval or the expiry of the rights to explore for E&E assets could lead to the impairment of E&E assets. These factors should not be considered exhaustive. Additional risks are outlined in the AIF of the Corporation available on SEDAR at www.sedar.com.

OUTLOOK

Pengrowth currently anticipates a 2012 capital program, excluding acquisitions, of $625 million, an increase of three percent from 2011 net capital expenditures of $609.1 million. Pengrowth s operated 2012 capital program is 100 percent focused on development of oil and liquids rich gas plays, with the majority of the capital to be spent in the three key areas of Swan Hills ($255 million), the Olds area ($85 million) and the Lindbergh SAGD ($59 million).

Execution of Pengrowth s 2012 capital program is expected to generate full year average production of between 74,500 and 76,500 boe per day, an increase of approximately two percent from our full year 2011 average production of 73,973 boe per day. Pengrowth s average production estimate for 2012 excludes any production associated with the Lindbergh pilot project.

Table of Contents

2012 operating expenses are forecast to be $384 million, essentially flat to 2011, however Pengrowth expects operating costs per boe to decrease to $13.89 due to additional production volumes.

Total G&A costs are expected to decrease for 2012 to $2.68 per boe when compared to the full year 2011 costs of $2.79 per boe. Included in Pengrowth s 2012 G&A forecast are non-cash G&A costs of approximately $0.49 per boe compared to $0.41 per boe in 2011.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On January 1, 2011, Pengrowth adopted International Financial Reporting Standards (IFRS) for financial reporting purposes, using a transition date of January 1, 2010. The financial statements for the year ended December 31, 2011 have been prepared in accordance with IFRS. Required comparative information has been restated from the previously published financial statements which were prepared in accordance with Canadian Generally Accepted Accounting Principles (previous GAAP). The adoption of IFRS has not had an impact on Pengrowth s operations, capital expenditures and overall cash flows. The most significant changes under IFRS relate to Pengrowth s accounting policies on Property, Plant and Equipment (PP&E), Asset Retirement Obligations (ARO) and Deferred Income Taxes. Pengrowth also adopted certain presentation policies that differ from previous GAAP. The following discusses the significant differences on the balances as at and for the three months and twelve months ended December 31, 2010 under IFRS compared to the amounts published under previous GAAP.

Property, Plant & Equipment (PP&E)

Depletion

Under previous GAAP, Pengrowth used total proved reserves in determining depletion. Under IFRS, the carrying amount of property, plant and equipment is depleted or amortized over the useful life of the assets. Pengrowth has determined that depleting on a total proved plus probable reserves basis better approximates the useful life of the assets.

Depletion was calculated using a unit of production method on the full cost pool of assets under previous GAAP. Under IFRS, depletion is calculated on a unit of production method at a field or group of fields.

These changes resulted in a lower depletion expense under IFRS compared to previous GAAP by approximately $27 million for the three months ended December 31, 2010 and $112 million for the year ended December 31, 2010.

Divestitures

Under previous GAAP, proceeds of divestitures of assets were deducted from the full cost pool without the recognition of a gain or loss unless the divesture resulted in a change in the full cost depletion rate of 20 percent or more. Under IFRS, gains or losses on disposition of assets are measured as the difference between the proceeds and carrying value of the assets divested.

Pengrowth recorded a gain of approximately $7 million in the three months ended December 31, 2010 and $18 million for the year ended December 31, 2010.

Under IFRS, the gain on equity investment was disclosed below the determination of operating income.

Impairment testing

Under IFRS, PP&E is grouped into Cash Generating Units (CGU) based on their ability to generate largely independent cash flows. Impairment is recognized if the carrying value of a CGU exceeds the greater of the fair value of the CGU or its value in use.

As CGUs are smaller groups of assets, impairments are expected to be recognized more frequently under IFRS. As of January 1, 2010 and December 31, 2010, no impairment was determined.

Under previous GAAP, impairment was recognized if the aggregated carrying value of the full cost pool exceeded the undiscounted cash flows from proved reserves. The amount of the impairment was the excess of the carrying value of the assets over the fair value of the proved plus probable reserves and the cost of unproven properties.

ARO

Discount Rate

Under previous GAAP, Pengrowth was required to use a credit adjusted discount rate in estimating the ARO, which was eight percent at the date of transition. Under IFRS, Pengrowth s policy is to estimate the ARO using a risk free discount rate on January 1, 2010.

Table of Contents

The effect of using a risk free discount rate of four percent resulted in an increase of $360 million to the ARO liability as at January 1, 2010 which was partly offset by changes to timing and cost estimates of $198 million on transition to IFRS. Accretion of ARO has decreased by approximately $1 million per quarter in 2010 as a result of using a lower discount rate.

As of December 31, 2010, an inflation rate of one and one half percent per annum and a discount rate of three and one half percent per annum was used to calculate the ARO liability. Under previous GAAP, a credit adjusted discount rate of eight percent per annum and inflation rate of one and one half percent per annum was used. As a result, the ARO liability under IFRS was $447 million as at December 31, 2010 as compared to $260 million as at December 31, 2010 under previous GAAP. Expected future escalated costs related to ARO were increased to $1,823 million as at December 31, 2010 as compared to $1,790 million as at December 31, 2010 under previous GAAP.

In addition, more frequent revisions of the ARO liability are expected due to fluctuations in the risk free rate.

Deferred Income Taxes

Each of the adjustments discussed above resulted in a change in deferred income taxes based on Pengrowth s effective tax rate.

In addition, taxable temporary differences in the legal entity financial statements of Pengrowth Energy Trust were required to be measured using the top marginal personal tax rate of 39 percent, resulting in a reduction to deferred income tax liability of $164 million on transition on January 1, 2010. This IFRS adjustment, plus an additional $23 million of temporary differences incurred during 2010, was reversed through deferred tax expense and shareholders capital upon conversion to a corporation on December 31, 2010.

Deferred tax expense of $35 million was recorded on IFRS adjustments to the 2010 income statement.

Reclassifications

Under previous GAAP, interest and financing charges, realized foreign exchange loss (gain), unrealized foreign exchange loss (gain), and accretion were disclosed as separate line items in the Statement of (Loss) Income. Under IFRS, these amounts were unchanged, but reported below the determination of operating income.

Under previous GAAP, amortization of injectants for miscible floods was disclosed separately; under IFRS amortization of injectants for miscible floods is included with depletion, depreciation and amortization. Interest paid is disclosed as a financing item in the Statement of Cash Flow.

Purchases of injectants are classified as a use of cash for investing activities under IFRS.

The Statement of Cash Flow includes a subtotal for Funds Flow from Operations which is determined as cash flow from operations after interest and financing charges but before changes in working capital and expenditures on remediation. Management believes that in addition to cash provided by operations, Funds Flow from Operations is a useful supplemental measure as it demonstrates the company s ability to generate cash flow necessary to fund dividends and capital investments.

Pengrowth s IFRS accounting policies are provided in Note 2 to the December 31, 2011 annual financial statements. In addition, Note 23 to the annual financial statements presents reconciliations between Pengrowth s 2010 previous GAAP results and the 2010 IFRS results. The reconciliations include January 1, 2010, and December 31, 2010 Balance Sheets as well as Statements of Income and Statements of Cash Flow for the year ended December 31, 2010.

FUTURE CHANGES IN ACCOUNTING POLICIES

IFRS 9: Financial Instruments (IFRS 9)

IFRS 9 is expected to be published in three parts. The first part, Phase 1 classification and measurement of financial instruments (IFRS 9, Phase 1), was published in October 2010.

IFRS 9, Phase 1, sets out the requirements for recognizing and measuring financial assets, financial liabilities and some contracts to buy or sell non-financial items. IFRS 9, Phase 1 simplifies measurement of financial asset by classifying all financial assets as those being recorded at amortized cost or being recorded at fair value. For financial assets recorded at fair value, any change in the fair value would be recognized in profit or loss. IFRS 9, Phase 1, is required to be adopted for years beginning on or after January 1, 2015 although earlier adoption is allowed. Pengrowth has not made any decision as to early adoption. Pengrowth is currently assessing the impact of this new standard.

Table of Contents

IFRS 10 Consolidated Financial Statements (IFRS 10)

IFRS 10 was published in May 2011. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements when an entity controls one or more other entities, including special purpose or variable interest entities. IFRS 10 also defines the principle of control and establishes control as the basis for determining which entities are consolidated in the consolidated financial statements. IFRS 10 is required to be adopted for years beginning on or after January 1, 2013. Earlier adoption is allowed and must be adopted in conjunction with IFRS 12 Disclosure of Interest in Other Entities. Based on Pengrowth s current corporate structure, no significant changes are anticipated as a result of adopting IFRS 10.

IFRS 11 Joint Arrangements (IFRS 11)

IFRS 11 was published in May 2011. IFRS 11 establishes principles for financial reporting by parties to a joint arrangement. IFRS 11 divides all joint arrangements into two categories: joint operations where the jointly controlling parties have rights to the assets and obligations for the liabilities relating to the arrangements, and joint ventures where the jointly controlling parties have rights to the net assets of the arrangement. Joint operations would be accounted for using the proportionate consolidation method where Pengrowth s proportionate interest in the revenues, expenses, assets and liabilities would be disclosed, consistent with Pengrowth s current accounting for joint operations. Joint ventures would be accounted for using the equity method of accounting, where the investment in the joint venture would be adjusted for Pengrowth s proportion of the net income or loss of the joint venture. IFRS 11 is required to be adopted for years beginning on or after January 1, 2013 although earlier adoption is allowed. A significant portion of Pengrowth petroleum and natural gas development and production activities are conducted with others and accordingly Pengrowth is undertaking an examination of each of these joint arrangements. The impact of adoption cannot be determined until this examination is complete.

IFRS 12 Disclosure of Interest in Other Entities (IFRS 12)

IFRS 12 was published in May 2011. IFRS 12 established the requirements for disclosure of ownership interests in subsidiaries, joint arrangements, associates and other entities. IFRS 12 requires disclosure of information that enables users of financial statements to evaluate the nature of, and risks associated with, its interests in other entities and the effects of those interests on its financial position, financial performance and cash flows. IFRS 12 is required to be adopted for years beginning on or after January 1, 2013. Earlier adoption is allowed. Pengrowth is currently assessing the impact of this new standard.

IFRS 13 Fair Value Measurements (IFRS 13)

IFRS 13 was published in May 2011. IFRS 13 defines fair value, sets out a framework for measuring fair value and requires disclosures about fair values. IFRS 13 applies to all other IFRSs that require or permit fair value measurements or disclosures about fair value measurements. IFRS 13 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. That definition of fair value emphasizes a market-based measurement, not an entity-specific measurement. IFRS 13 is required to be adopted for years beginning on or after January 1, 2013. Earlier adoption is allowed. Pengrowth is currently assessing the impact of this new standard.

IAS 28 Investments in Associates (IAS 28)

IAS 28 was published in May 2011. IAS 28 prescribes the accounting for investments in associates and contains the requirements for the application of the equity method to investments in associates and joint ventures. The standard is applied prospectively for annual periods beginning on or after January 1, 2013. Earlier adoption is permitted. Based on Pengrowth s current corporate structure, no significant changes are anticipated as a result of adopting IAS 28.

DISCLOSURE CONTROLS AND PROCEDURES

As a Canadian reporting issuer with securities listed on both the TSX and the NYSE, Pengrowth is required to comply with Multilateral Instrument 52-109 Certification of Disclosure in Issuers Annual and Interim Filings, as well as the Sarbanes Oxley Act (SOX) enacted in the United States. Both the Canadian and U.S. certification rules include similar requirements where both the CEO and the Chief Financial Officer (CFO) must assess and certify as to the effectiveness of the disclosure controls and procedures as defined in Canada by Multilateral Instrument 52-109 Certification of Disclosure in Issuers Annual and Interim Filings and in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended.

The CEO, Derek Evans, and the CFO, Christopher Webster, evaluated the effectiveness of Pengrowth s disclosure controls and procedures for the year ending December 31, 2011. This evaluation considered the functions performed by its Disclosure Committee, the review and oversight of all executive officers and the board, as well as the process and systems in place for filing regulatory and public information. Pengrowth s established review process and disclosure controls are designed to provide reasonable assurance that all required information, reports and filings required under Canadian securities legislation and United States securities laws are properly submitted and recorded in accordance with those requirements.

Table of Contents

Based on that evaluation, the CEO and CFO concluded that the design and operation of our disclosure controls and procedures were effective at the reasonable assurance level as at December 31, 2011, to ensure that information required to be disclosed by us in reports that we file under Canadian and U.S. securities laws is gathered, recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws and is accumulated and communicated to the management of Pengrowth Energy Corporation, including the CEO and CFO, to allow timely decisions regarding required disclosure as required under Canadian and U.S. securities laws.

It should be noted that while Pengrowth s CEO and CFO believe that Pengrowth s disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that Pengrowth s disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

INTERNAL CONTROL OVER FINANCIAL REPORTING

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended and in Canada as defined in Multilateral Instrument 52-109 Certification of Disclosure in Issuers Annual and Interim Filings. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with IFRS for note disclosure purposes. Our internal control over financial reporting includes those policies and procedures that: pertain to the maintenance of records that in reasonable detail accurately and fairly reflect our transactions and disposition of the assets; provide reasonable assurance that transactions are recorded as necessary to permit preparation of our financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of our assets are being made only in accordance with authorizations of our management and directors; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of our assets that could have a material effect on our financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our internal control over financial reporting as of December 31, 2011. In making this evaluation, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework.

Based on our evaluation, management concluded that our internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of internal control over financial reporting as of December 31, 2011 was audited by KPMG LLP, an independent registered public accounting firm, as stated in their report, which is included with our audited consolidated financial statements for the year ended December 31, 2011. No changes were made to our internal control over financial reporting during the year ending December 31, 2011 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

Table of Contents

APPENDIX C

FINANCIAL STATEMENTS OF PENGROWTH ENERGY CORPORATION, INCLUDING MANAGEMENT S REPORT TO SHAREHOLDERS AND THE AUDITORS REPORTS

Table of Contents

MANAGEMENT S REPORT TO SHAREHOLDERS

MANAGEMENT S RESPONSIBILITY TO SHAREHOLDERS

The financial statements and the notes to the financial statements are the responsibility of the management of Pengrowth Energy Corporation. They have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board which have been adopted in Canada. Financial information that is presented in the Management Discussion and Analysis is consistent with the financial statements.

In preparation of these statements, estimates are sometimes necessary because a precise determination of certain assets and liabilities is dependant on future events. Management believes such estimates have been based on careful judgments and have been properly reflected in the accompanying financial statements.

Management is responsible for the reliability and integrity of the financial statements, the notes to the financial statements, and other financial information contained in this report. In order to ensure that management fulfills its responsibilities for financial reporting we have established an organizational structure that provides appropriate delegation of authority, division of responsibilities, and selection and training of properly qualified personnel. Management is also responsible for the development of internal controls over the financial reporting process.

The Board of Directors (the Board) is assisted in exercising its responsibilities through the Audit and Risk Committee (the Committee) of the Board, which is composed of four independent directors. The Committee meets regularly with management and the independent auditors to satisfy itself that management s responsibilities are properly discharged, to review the financial statements and to recommend approval of the financial statements to the Board.

KPMG LLP, the independent auditors appointed by the shareholders, have audited Pengrowth Energy Corporation s consolidated financial statements in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) and provided an independent professional opinion. The auditors have full and unrestricted access to the Committee to discuss the audit and their related findings as to the integrity of the financial reporting process.

Derek W. Evans
President and Chief Executive Officer
February 28, 2012

Christopher G. Webster
Chief Financial Officer

Table of Contents

INDEPENDENT AUDITORS REPORT OF REGISTERED PUBLIC ACCOUNTING FIRM

TO THE SHAREHOLDERS AND BOARD OF DIRECTORS OF PENGROWTH ENERGY CORPORATION

We have audited the accompanying financial statements of Pengrowth Energy Corporation (the Corporation), which comprise the balance sheets as at December 31, 2011, December 31, 2010 and January 1, 2010, the statements of income, shareholders equity and cash flow for the years ended December 31, 2011 and December 31, 2010, and notes, comprising a summary of significant accounting policies and other explanatory information.

MANAGEMENT S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

AUDITORS RESPONSIBILITY

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity s preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the financial statements present fairly, in all material respects, the balance sheet of the Corporation as at December 31, 2011, December 31, 2010 and January 1, 2010, and its financial performance and its cash flow for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

OTHER MATTER

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Corporation s internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 28 , 2012 expressed an unqualified opinion on the effectiveness of the Corporation s internal control over financial reporting.

Chartered Accountants
Calgary, Canada
February 28, 2012

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

TO THE SHAREHOLDERS AND BOARD OF DIRECTORS OF PENGROWTH ENERGY CORPORATION

We have audited Pengrowth Energy Corporation s (the Corporation) internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Corporation s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report to the Shareholders. Our responsibility is to express an opinion on the Corporation s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

An entity s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. An entity s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the balance sheet of the Corporation as of December 31, 2011, December 31, 2010 and January 1, 2010, and the related statements of income, shareholders equity and cash flow for the years ended December 31, 2011 and December 31, 2010, and our report dated February 28, 2012 expressed an unqualified opinion on those financial statements.

Chartered Accountants
Calgary, Canada
February 28, 2012

Table of Contents

BALANCE SHEETS

(Stated in thousands of dollars)

	Note	As at December 31, 2011	As at December 31, 2010 (Note 23)	As at January 1, 2010 (Note 23)
ASSETS				
Current Assets				
Cash and cash equivalents		$ 36,722	$ 2,849	$
Accounts receivable		183,814	189,616	182,342
Fair value of risk management contracts	18	643	13,550	14,001
		221,179	206,015	196,343
Deferred income taxes				40,917
Other assets	5	84,712	54,115	53,011
Property, plant and equipment	6	4,074,434	3,738,016	3,737,184
Exploration and evaluation assets	7	563,751	511,569	67,597
Goodwill	8	700,652	716,891	660,896
TOTAL ASSETS		$ 5,644,728	$ 5,226,606	$ 4,755,948
LIABILITIES AND SHAREHOLDERS EQUITY				
Current Liabilities				
Bank indebtedness	10	$	$ 22,000	$ 11,563
Accounts payable		273,344	240,952	185,337
Dividends payable		25,220	22,534	40,590
Fair value of risk management contracts	18	39,753	9,278	17,555
Current portion of long term debt				157,546
Current portion of provisions	11	20,149	20,488	21,227
		358,466	315,252	433,818
Fair value of risk management contracts	18	26,487	31,416	23,269
Convertible debentures	9			74,828
Long term debt	10	1,007,686	1,024,367	907,599
Provisions	11	646,998	434,532	439,064
Deferred income taxes	12	257,838	238,694	
		2,297,475	2,044,261	1,878,578
Shareholders Equity				
Shareholders capital	13	3,525,222	3,171,719	4,927,324
Equity portion of convertible debentures				160
Contributed surplus		17,697	10,626	18,617
Deficit	13	(195,666)		(2,068,731)
		3,347,253	3,182,345	2,877,370
Commitments	20			
Contingencies	21			
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY		$ 5,644,728	$ 5,226,606	$ 4,755,948

See accompanying notes to the financial statements.

Approved on behalf of the Board of Directors of Pengrowth Energy Corporation

Director Director

Table of Contents

STATEMENTS OF INCOME

(Stated in thousands of dollars, except per share amounts)

	Note	Year ended December 31 2011	2010 (Note 23)
REVENUES			
Oil and gas sales		$ 1,453,735	$ 1,368,713
Royalties, net of incentives		(277,945)	(252,699)
		1,175,790	1,116,014
Unrealized (loss) gain on commodity risk management	18	(39,951)	6,949
		1,135,839	1,122,963
EXPENSES			
Operating		382,024	357,178
Transportation		25,716	25,109
General and administrative		75,312	50,894
Depletion, depreciation and amortization	6	437,923	432,381
Impairment of assets	6, 8	27,360	
		948,335	865,562
OPERATING INCOME		187,504	257,401
Other (income) expense items			
Gain on investments	4, 5	(23,000)	(73,756)
Gain on disposition of properties		(12,647)	(18,425)
Unrealized foreign exchange loss (gain)	19	19,098	(49,918)
Realized foreign exchange loss	19	1,583	2,061
Interest and financing charges		75,924	70,464
Accretion	11	15,618	17,744
Other expense (income)		4,068	(11,926)
INCOME BEFORE TAXES		106,860	321,157
Deferred income tax expense	12	22,328	171,321
NET INCOME AND COMPREHENSIVE INCOME		$ 84,532	$ 149,836
NET INCOME PER SHARE	16		
Basic		$ 0.25	$ 0.50
Diluted		$ 0.25	$ 0.49

See accompanying notes to the financial statements.

Table of Contents

STATEMENTS OF CASH FLOW

(Stated in thousands of dollars)

	Note	Year Ended December 31 2011		2010 (Note 23)	
CASH PROVIDED BY (USED FOR):					
OPERATING					
Net income and comprehensive income		$	84,532	$	149,836
Depletion, depreciation and accretion			453,541		450,125
Impairment of assets	6, 8		27,360		
Deferred income tax expense			22,328		171,321
Contract liability amortization			(1,677)		(1,728)
Unrealized foreign exchange loss (gain)	19		19,098		(49,918)
Unrealized loss (gain) on commodity risk management	18		39,951		(6,949)
Share based compensation	13		11,024		4,565
Non-cash gain on investments	4, 5		(23,000)		(73,756)
Gain on disposition of properties			(12,647)		(18,425)
Other items			(547)		1,175
Funds flow from operations			619,963		626,246
Interest and financing charges			75,924		70,464
Expenditures on remediation			(21,939)		(20,926)
Changes in non-cash operating working capital	15		19,135		11,063
			693,083		686,847
FINANCING					
Dividends paid			(277,512)		(250,640)
Bank (repayment) indebtedness			(22,000)		10,437
Long term debt decrease	10		(39,000)		(24,581)
Redemption of convertible debentures	9				(76,610)
Interest paid			(72,612)		(71,528)
Other financing cost			(1,605)		(3,110)
Proceeds from equity issues			345,774		26,980
			(66,955)		(389,052)
INVESTING					
Capital expenditures			(608,463)		(333,842)
Other property acquisitions			(8,628)		(20,171)
Proceeds on property dispositions			16,935		60,721
Purchase of injectants			(4,126)		(9,324)
Other investments					(2,906)
Change in remediation trust funds			(6,030)		(6,952)
Change in non-cash investing working capital	15		18,057		17,528
			(592,255)		(294,946)
CHANGE IN CASH AND CASH EQUIVALENTS			33,873		2,849
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR			2,849		
CASH AND CASH EQUIVALENTS AT END OF YEAR		$	36,722	$	2,849

See accompanying notes to the financial statements.

Table of Contents

STATEMENTS OF SHAREHOLDERS EQUITY

(Stated in thousands of dollars)

		Year ended December 31	
	Note	2011	2010
SHAREHOLDERS CAPITAL			
Balance, beginning of year		$ 3,171,719	$
Issued to trust unitholders			5,270,631
Issued to exchangable shareholders			52,567
Share based compensation		8,086	
Issued under Dividend Reinvestment Plan		54,698	
Issued for cash on equity issue		300,086	
Share issue cost, net of tax		(9,367)	
Elimination of deficit	1		(2,151,479)
Balance, end of year		3,525,222	3,171,719
TRUST UNITHOLDERS CAPITAL			
Balance, beginning of year			4,927,324
Trust unit based compensation			7,250
Issued under Distribution Reinvestment Plan			24,072
Issued for the Monterey business combination			307,648
Issued on redemption of Exchangeable shares			11,339
Issue costs, net of tax			(623)
Change in effective tax rate on issue costs	23		(6,379)
Trust units exchanged for common shares under the Arrangement	1		(5,270,631)
Balance, end of year			
EXCHANGEABLE SHARES			
Balance, beginning of year			
Issued for the Monterey business combination			54,939
Redemptions at fair value of trust units or common shares			8,967
Redeemed for trust units			(11,339)
Exchanged for common shared under the Agreement	1		(52,567)
Balance, end of year			
CONTRIBUTED SURPLUS			
Balance, beginning of year		10,626	18,617
Share based compensation		11,617	4,565
Exercise of share based compensation awards		(4,546)	(3,589)
Redemption of exchangable shares			(8,967)
Balance, end of year		17,697	10,626
DEFICIT			
Balance, beginning of year			(2,068,731)
Net income		84,532	149,836
Dividends declared		(280,198)	(232,584)
Elimination of deficit	1		2,151,479
Balance, end of year		(195,666)	
TOTAL SHAREHOLDERS EQUITY		$ 3,347,253	$ 3,182,345

See accompanying notes to the financial statements.

Table of Contents

PENGROWTH ENERGY CORPORATION

NOTES TO FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2011 AND 2010

(Tabular amounts are stated in thousands of dollars except per share amounts and as otherwise stated)

1. CORPORATE STRUCTURE

Pengrowth Energy Corporation (the Corporation or Pengrowth) is a Canadian resource company that is engaged in the production, development, exploration and acquisition of oil and natural gas assets. The Corporation was formed through a unitholder and Court approved reorganization involving Pengrowth Energy Trust (the Trust), Pengrowth Corporation, its subsidiaries and the security holders of the Trust and Pengrowth Corporation pursuant to a Plan of Arrangement (the Arrangement) under the Business Corporations Act (Alberta).

On December 31, 2010 (the Date of Conversion), the Trust completed its conversion from an open-end investment trust to a corporation through a business combination resulting in the unitholders of the Trust and the exchangeable shareholders of Pengrowth Corporation owning all the common shares of the Corporation. Unitholders of the Trust received common shares in the Corporation on a one-for-one basis. Exchangeable shareholders of Pengrowth Corporation received 1.02308 common shares of the Corporation for each exchangeable share held. Pursuant to the Arrangement agreement, shareholders capital was reduced by the amount of the consolidated deficit of the Trust on December 31, 2010. The management team and Board of Directors of the Corporation were initially comprised of the former management team and elected members of the Board of Directors of the Trust.

The Corporation effected an internal reorganization subsequent to the date of conversion whereby, among other things, the Trust and its subsidiaries were dissolved and the Corporation received all the assets and assumed all the liabilities of the Trust.

The Arrangement was accounted for on a continuity of interest basis and accordingly, the consolidated financial statements for periods prior to the date of conversion reflect the financial position, results of operations and cash flows as if the Corporation had always carried on the business formerly carried on by the Trust. These financial statements may at times refer to common shares, shareholders, shareholders capital and dividends which, prior to the Arrangement, were referred to as trust units, trust unitholders, trust unitholders capital and distributions, respectively. References made to trust units are those issued by the Trust. Comparative amounts in these financial statements will also reflect the history of the Trust and its subsidiaries.

2. SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

These financial statements have been prepared in accordance with the International Financial Reporting Standards (IFRS) issued by the International Accounting Standards Board (IASB) and International Financial Reporting Interpretations Committee (IFRIC).

These IFRS financial statements include comparative information for the year ended December 31, 2010 which has been prepared in accordance with IFRS. Previously, Pengrowth prepared and published its annual and interim consolidated financial statements in accordance with Canadian Generally Accepted Accounting Principles (previous GAAP). Pengrowth has provided a reconciliation of comparative amounts to the previously released financial statements prepared under previous GAAP, see Note 23.

The financial statements were authorized for release by the Board of Directors on February 28, 2012.

PROPERTY, PLANT AND EQUIPMENT (PP&E) AND EXPLORATION AND EVALUATION ASSETS (E&E ASSETS)

Pengrowth capitalizes all costs of developing and acquiring oil and gas properties. These costs include lease acquisition costs, geological and geophysical expenditures, costs of drilling and completion of wells, plant and production equipment costs and related overhead charges.

Pengrowth capitalizes a portion of general and administrative costs and stock based compensation expense associated with exploration and development activities.

Table of Contents

Repairs and maintenance costs are expensed as incurred.

Exploration and Evaluation Assets

Costs of exploring for and evaluating oil and natural gas properties are capitalized within exploration and evaluation assets. These exploration and evaluation costs include lease acquisition costs, geological and geophysical expenditures, costs of drilling and completion of wells, plant and production equipment costs and related overhead charges. E&E Assets do not include costs of general prospecting, or evaluation costs incurred prior to having obtained the legal rights to explore an area, which are expensed as incurred. Interest is not capitalized on E&E Assets.

E&E Assets are not depleted or depreciated and are carried forward until technical feasibility and commercial viability is considered to be determined. The technical feasibility and commercial viability is generally considered to be determined when proved plus probable reserves are determined to exist and the commercial production of oil and gas has commenced. A review of each exploration license or field is carried out, at least annually, to ascertain whether the project is technically feasible and commercially viable. Upon determination of technical feasibility and commercial viability, E&E Assets attributable to those reserves are first tested for impairment and then reclassified from E&E Assets to PP&E.

Property, Plant and Equipment

PP&E is stated at cost, less accumulated depletion, depreciation and amortization, and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, costs attributable to bringing the asset into operation, the initial estimate of asset retirement obligation and, for qualifying assets, borrowing costs. When significant parts of an item of PP&E, including oil and natural gas interests, have different useful lives, they are accounted for as separate items.

The cost of PP&E at January 1, 2010, the date of transition to IFRS, was determined in accordance with the deemed cost exemption permitted by IFRS 1 First-time Adoption of International Financial Reporting Standards for full cost oil and gas entities. Under this method, the net book value of the oil and natural gas interests, as determined under previous GAAP was allocated to specific cost items based on the pro-rata share of proved plus probable reserve values as of January 1, 2010.

Subsequent Costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of PP&E are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of PP&E are expensed as incurred.

Pengrowth capitalizes a portion of general and administrative costs directly associated with exploration and development activities. Pengrowth would capitalize interest incurred in construction of qualifying assets, if applicable. Qualifying assets are defined by Pengrowth as capital projects that require capital expenditures over a period greater than one year, in order to produce oil or gas from a specific property.

Dispositions

Gains or losses are recognized in the Statement of Income on dispositions of PP&E and certain E&E assets, including asset swaps, farm-out transactions and property dispositions. The gain or loss is measured as the difference between the fair value of the proceeds received and the carrying value of the assets disposed, including capitalized future asset retirement obligations.

Depletion and Depreciation

The net carrying value of developed or producing fields or groups of fields is depleted using the unit of production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually. Pengrowth s total proved plus probable reserves are estimated by an independent reserve evaluator and represent the best estimate of quantities of oil, natural gas and related substances to be commercially recoverable from known accumulations, from a given date forward, based on geological and engineering data. It is equally likely that the actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves. Properties with no remaining production and reserves are fully depleted in the year that production ceases.

Table of Contents

For other assets, depreciation is recognized in profit or loss using either a straight line or declining balance basis over the estimated useful lives of each part of an item of PP&E. The estimated useful lives for other assets for the current and comparative periods are as follows:

Office Equipment	60 months
Leasehold Improvements	120 months (lease term)
Computers	36 months
Deferred Hydrocarbon Injectants	24 months

Depreciation methods, useful lives and residual values are reviewed annually.

GOODWILL AND BUSINESS COMBINATIONS

Goodwill

Goodwill may arise on business combinations. Goodwill is stated at cost less accumulated impairment.

Acquisitions prior to January 1, 2010

As part of the transition to IFRS, the Corporation elected to not restate business combinations that occurred prior to January 1, 2010. In respect of acquisitions prior to January 1, 2010, goodwill represents the amount recognized under the Corporation s previous GAAP.

Acquisitions on or after January 1, 2010

For acquisitions on or after January 1, 2010, goodwill as determined under IFRS represents the excess of the cost of the acquisition over the net fair value of the identifiable assets, liabilities and contingent liabilities of the acquired assets or company. When the excess is negative, it is recognized immediately in the Statement of Income.

IMPAIRMENT

Non-Financial Assets

Property, Plant and Equipment

For the purpose of impairment testing, PP&E is grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets cash generating unit (the CGU).

CGUs are assessed at least annually or when there is an indication of impairment, such as decreased commodity prices or downward revisions in reserves volumes. If any such indication exists, the CGUs are tested for impairment. An impairment loss is recognized to the extent the carrying value of the CGU exceeds its recoverable amount. Impairment losses are recognized in the Statement of Income.

The recoverable amount of a CGU is the higher of its value in use and the fair value less costs to sell. In determining the recoverable amount, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the cost of capital, which take into account the time value of money and the risks specific to the asset. The recoverable amount is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit on a pro rata basis.

An impairment loss in respect of goodwill cannot be reversed. In respect of other assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. In such circumstances, the recoverable amount is determined and to the extent the loss is reduced, it is reversed. An impairment loss is reversed only to the lesser of the revised recoverable amount or the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

Exploration and Evaluation Assets

E&E assets are tested for impairment where there is an indication that a particular E&E project may be impaired. Examples of indicators of impairment include the decision to no longer pursue the E&E project, an expiry of the rights to explore in an area, or failure to receive regulatory approval. In addition, E&E assets are assessed for impairment upon their reclassification to producing assets (oil and natural gas interests in PP&E). In assessing the impairment of E&E assets, the carrying value of the E&E assets would be compared to their estimated recoverable amount and, in certain circumstances, could include any surplus from PP&E impairment testing of related CGUs. The impairment of E&E assets and any eventual impairment thereof would be recognized in the Statement of Income.

Goodwill

For goodwill and other intangible assets that have indefinite lives or that are not yet available for use, an impairment test is completed each year at December 31. In assessing the impairment of goodwill, the carrying value of goodwill is compared to the excess of the recoverable amount over the carrying amount of the PP&E and E&E assets, as applicable, within the CGU or groups of CGUs where the acquired properties are grouped. An impairment loss is recognized if the carrying amount of the goodwill exceeds the excess of the recoverable amount above the carrying amount of the CGU or CGUs. Any impairment of goodwill is recognized in depletion, depreciation and amortization expense in the Statement of Income.

Financial Assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence, including failure to pay on time, indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in the Statement of Income. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in the Statement of Income.

PROVISIONS

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not permitted for future operating losses.

Asset Retirement Obligations (ARO)

Pengrowth initially recognizes the net present value of an ARO in the period in which it is incurred when a reasonable estimate of the net present value can be made. The net present value of the estimated ARO is recorded as a liability, with a corresponding increase in the carrying amount of the related asset. The capitalized asset is depleted on the unit of production method based on proved plus probable reserves. The liability is increased each reporting period due to the passage of time and the amount of such accretion is expensed to income in the period. Actual costs incurred upon the settlement of the ARO are charged against the ARO. Management reviews the ARO estimate and changes, if any, are applied prospectively. Revisions made to the ARO estimate are recorded as an increase or decrease to the ARO liability with a corresponding change made to the carrying amount of the related asset. The carrying amount of both the liability and the capitalized asset, net of accumulated depreciation, are derecognized if the asset is subsequently disposed.

Pengrowth has placed cash in segregated remediation trust fund accounts to fund certain ARO for the Judy Creek properties and the Sable Offshore Energy Project (SOEP). These funds are reflected in Other Assets on the balance sheet.

Contract Liabilities Provision

Pengrowth assumed firm pipeline commitments in conjunction with certain prior period acquisitions. The fair values of these contracts were estimated on the date of acquisition and the amount recorded is reduced as the contracts settle.

Table of Contents

DEFERRED INCOME TAXES

Income tax expense is comprised of current and deferred tax. Income tax expense is recognized in the Statement of Income except to the extent that it relates to items recognized directly in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the asset and liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on deferred income tax liabilities and assets is recognized in income in the period the change occurs. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset current tax liabilities and assets, and they relate to income taxes levied by the same tax authority on the same taxable entity.

Pengrowth s policy for income tax uncertainties is that tax benefits will be recognized only when it is more likely than not the position will be sustained on examination.

SHARE BASED COMPENSATION PLANS

Pengrowth has share based compensation plans, which are described in Note 14. Compensation expense is based on the estimated fair value of the share based compensation award at the date of grant. Compensation expense associated with the share based compensation plans are recognized in income over the vesting period of the plan with a corresponding increase to contributed surplus. Pengrowth estimates the forfeiture rate for each type of share based award at the date of grant. Any consideration received upon the exercise of share unit rights and options together with the amount of non-cash compensation expense recognized in contributed surplus is recorded as an increase in shareholders capital at the time of exercise.

Pengrowth does not have any outstanding share based compensation plans that call for settlement in cash or other assets. Grants of such items, if any, will be recorded as liabilities, with changes in the liabilities charged to net income, based on the estimated fair value.

FINANCIAL INSTRUMENTS

Financial instruments are utilized by Pengrowth to manage its exposure to commodity price fluctuations, foreign currency and interest rate exposures. Pengrowth s policy is not to utilize financial instruments for trading or speculative purposes.

Financial instruments are classified into one of five categories: (i) fair value through profit or loss, (ii) held to maturity investments, (iii) loans and receivables, (iv) available for sale financial assets or (v) other liabilities.

Accounts receivable are classified as loans and receivables which are measured at amortized cost.

Investments held in the remediation trust funds and other investments have been designated as fair value through profit or loss and are measured at fair value. Any change in the fair value is recognized in income as other income or expense.

Bank indebtedness, accounts payable, dividends payable and long term debt have been classified as other liabilities which are measured at amortized cost using the effective interest rate method.

All derivatives must be classified as held for trading and measured at fair value with changes in fair value over a reporting period recognized in net income. The receipts or payments arising from derivative commodity contracts are included in the realized gain (loss) on commodity risk management. Unrealized gains and losses on derivative commodity contracts are included in the unrealized gain (loss) on commodity risk management. The receipts or payments arising from derivative power contracts are included in operating expense. The unrealized gains and losses on derivative power contracts are included in other income (expense). The difference between the interest payments on the U.K. Pound Sterling denominated debt after the foreign exchange swaps and the interest expense recorded at the average foreign exchange rate is included in interest expense. Unrealized gains (losses) on these swaps, covering the principal and interest on the U.K. Pound Sterling denominated debt, are included in unrealized foreign exchange gains (losses).

Transaction costs incurred in connection with the issuance of term debt instruments with a maturity of greater than one year are deducted against the carrying value of the debt and amortized to net income using the effective interest rate method over the expected life of the debt.

Table of Contents

Pengrowth capitalizes transaction costs incurred in connection with the renewal of the revolving credit facility with a maturity date greater than one year and amortizes the cost to net income on a straight line basis over the term of the facility.

FOREIGN CURRENCY

The functional and reporting currency of the Corporation is Canadian dollars. Transactions in foreign currencies are translated to Canadian dollars at the exchange rates on the date of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated into Canadian dollars at the exchange rate in effect on the balance sheet date. Foreign exchange gains and losses are recognized in income.

JOINTLY CONTROLLED OPERATIONS

A significant proportion of Pengrowth s petroleum and natural gas development and production activities are conducted through jointly controlled operations with others and accordingly, the accounts reflect only Pengrowth s interest in such activities.

RELATED PARTIES

Related parties are persons or entities that have control or significant influence over Pengrowth, as well as key management personnel. A senior officer of Pengrowth was a member of the Board of Directors of Monterey Exploration Ltd (Monterey), a company that was acquired in September 2010 (Note 4). Note 22 provides information on compensation expense related to key management personnel. Pengrowth has no significant transactions with any other related parties.

REVENUE RECOGNITION

Revenue from the sale of oil and natural gas is recognized when the product is delivered and collection is reasonably assured. Revenue from processing and other miscellaneous sources is recognized upon completion of the relevant service.

EQUITY INVESTMENT

Pengrowth utilizes the equity method of accounting for investments subject to significant influence. Under this method, investments are initially recorded at cost and adjusted thereafter to include Pengrowth s pro rata share of post-acquisition earnings. Any dividends received or receivable from the investee would reduce the carrying value of the investment.

ESTIMATES

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingencies at the date of the financial statements, and revenues and expenses during the reporting year. Actual results could differ from those estimated.

In particular, information about significant areas of estimation uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in the financial statements are described below:

Estimating oil and gas reserves

Pengrowth engages a qualified, independent oil and gas reserves evaluator to perform an estimation of the Corporation s oil and gas reserves at least annually. Reserves form the basis for the calculation of depletion charges and assessment of impairment of oil and gas assets. Reserves are estimated using the reserve definitions and guidelines prescribed by National Instrument 51-101 (NI 51-101) and the Canadian Oil and Gas Evaluation Handbook (COGEH).

Proved plus probable reserves are defined as the best estimate of quantities of oil, natural gas and related substances estimated to be commercially recoverable from known accumulations, from a given date forward, based on drilling, geological, geophysical and engineering data, the use of established technology and specified economic conditions. It is equally likely that the actual remaining quantities recovered will be greater than or less than the sum of the estimated proved plus probable reserves. The estimates are made using all available geological and reservoir data as well as historical production data. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes and reservoir performance or a change in Pengrowth s plans with respect to future development or operating practices.

Determination of CGUs

The recoverability of development and production asset carrying values are assessed at the CGU level. Determination of what constitutes a CGU is subject to management s judgment. The asset composition of a CGU can directly impact the recoverability of the assets included therein. In assessing the recoverability of oil and gas properties, each CGU s carrying value is compared to its recoverable amount, defined as the greater of fair value less costs to sell and value in use.

Asset Retirement Obligation

Pengrowth estimates obligations under environmental regulations in respect of decommissioning and site restoration. These obligations are determined based on the expected present value of expenses required in the process of plugging and abandoning wells, dismantling of wellheads, production and transportation facilities and restoration of producing areas in accordance with relevant legislation, discounted from the date when expenses are expected to be incurred. Most of the abandonment of future expenses, estimated logistics of performing abandonment work and the discount rate used to calculate the present value of future expenses would have a significant effect on the carrying amount of the decommissioning provision.

Impairment testing

The impairment testing of PP&E is completed for each CGU, and is based on estimates of proved plus probable reserves, production rates, oil and natural gas prices, future costs, discount rate and other relevant assumptions. The impairment assessment of goodwill is based on the estimated fair value of Pengrowth s CGUs. By their nature, these estimates are subject to measurement uncertainty and may impact the financial statements of future periods.

Valuation of trade and other receivables, and prepayments to suppliers

Management estimates the likelihood of the collection of trade and other receivables and recovery of prepayments based on an analysis of individual accounts. Factors taken into consideration include the aging of receivables in comparison with the credit terms allowed to customers and the financial position and collection history with the customer. Should actual collections be less than estimates, Pengrowth would be required to record an additional expense.

NET INCOME PER SHARE

Basic net income per share is calculated using the weighted average number of shares outstanding for the year. Diluted net income per share amounts includes the dilutive effect of common share rights and options, deferred entitlement share units and other share units under the new long term incentive plans using the treasury stock method. The treasury stock method assumes that any proceeds obtained on the exercise of in-the-money share unit rights and options would be used to purchase common shares at the average trading price during the period.

CASH AND TERM DEPOSITS

Cash and term deposits include demand deposits and term deposits with original maturities of less than 90 days.

COMPARATIVE FIGURES

Certain comparative figures in the prior periods have been reclassified to conform to the presentation adopted in the current year, including the presentation of oil and gas sales, operating expenses, and transportation on the Statements of Income.

3. RECENT ACCOUNTING PRONOUNCEMENTS

IFRS 9: Financial Instruments (IFRS 9)

IFRS 9 is expected to be published in three parts. The first part, Phase 1 classification and measurement of financial instruments (IFRS 9, Phase 1), was published in October 2010.

IFRS 9, Phase 1, sets out the requirements for recognizing and measuring financial assets, financial liabilities and some contracts to buy or sell non-financial items. IFRS 9, Phase 1 simplifies measurement of financial asset by classifying all financial assets as those being recorded at amortized cost or being recorded at fair value. For financial assets recorded at fair value, any change in the fair value would be recognized in profit or loss. IFRS 9, Phase 1, is required to be adopted for years beginning on or after January 1, 2015 although earlier adoption is allowed. Pengrowth has not made any decision as to early adoption. Pengrowth is currently assessing the impact of this new standard.

IFRS 10 Consolidated Financial Statements (IFRS 10)

IFRS 10 was published in May 2011. IFRS 10 establishes principles for the presentation and preparation of consolidated financial statements when an entity controls one or more other entities, including special purpose or variable interest entities. IFRS 10 also defines the principle of control and establishes control as the basis for determining which entities are consolidated in the consolidated financial statements. IFRS 10 is required to be adopted for years beginning on or after January 1, 2013. Earlier adoption is allowed and must be adopted in conjunction with IFRS 12 Disclosure of Interest in Other Entities. Based on Pengrowth s current corporate structure, no significant changes are anticipated as a result of adopting IFRS 10.

Table of Contents

IFRS 11 Joint Arrangements (IFRS 11)

IFRS 11 was published in May 2011. IFRS 11 establishes principles for financial reporting by parties to a joint arrangement. IFRS 11 divides all joint arrangements into two categories: joint operations where the jointly controlling parties have rights to the assets and obligations for the liabilities relating to the arrangements, and joint ventures where the jointly controlling parties have rights to the net assets of the arrangement. Joint operations would be accounted for using the proportionate consolidation method where Pengrowth s proportionate interest in the revenues, expenses, assets and liabilities would be disclosed, consistent with Pengrowth s current accounting for joint operations. Joint ventures would be accounted for using the equity method of accounting, where the investment in the joint venture would be adjusted for Pengrowth s proportion of the net income or loss of the joint venture. IFRS 11 is required to be adopted for years beginning on or after January 1, 2013 although earlier adoption is allowed. A significant portion of Pengrowth petroleum and natural gas development and production activities are conducted with others and accordingly Pengrowth is undertaking an examination of each of these joint arrangements. The impact of adoption cannot be determined until this examination is complete.

IFRS 12 Disclosure of Interest in Other Entities (IFRS 12)

IFRS 12 was published in May 2011. IFRS 12 established the requirements for disclosure of ownership interests in subsidiaries, joint arrangements, associates and other entities. IFRS 12 requires disclosure of information that enables users of financial statements to evaluate the nature of, and risks associated with, its interests in other entities and the effects of those interests on its financial position, financial performance and cash flows. IFRS 12 is required to be adopted for years beginning on or after January 1, 2013. Earlier adoption is allowed. Pengrowth is currently assessing the impact of this new standard.

IFRS 13 Fair Value Measurements (IFRS 13)

IFRS 13 was published in May 2011. IFRS 13 defines fair value, sets out a framework for measuring fair value and requires disclosures about fair values. IFRS 13 applies to all other IFRSs that require or permit fair value measurements or disclosures about fair value measurements. IFRS 13 defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. That definition of fair value emphasizes a market-based measurement, not an entity-specific measurement. IFRS 13 is required to be adopted for years beginning on or after January 1, 2013. Earlier adoption is allowed. Pengrowth is currently assessing the impact of this new standard.

IAS 28 Investments in Associates

International Accounting Standard 28 (IAS 28) was published in May 2011. IAS 28 prescribes the accounting for investments in associates, which are investments is entities over which the investor has significant influence but the investment is neither a subsidiary nor a joint venture, and contains the requirements for the application of the equity method to investments in associates and joint ventures. The standard is applied prospectively for annual periods beginning on or after January 1, 2013. Earlier adoption is permitted. Based on Pengrowth s current corporate structure, no significant changes are anticipated as a result of adopting IAS 28.

4. MONTEREY ACQUISITION

Pengrowth and Monterey completed a business combination (the Combination) on September 15, 2010 whereby each Monterey securityholder elected to receive either: (i) 0.8298 of a trust unit or (ii) 0.8298 of an exchangeable share of Pengrowth Corporation with each exchangeable share being exchangeable to a trust unit. The Combination resulted in Pengrowth acquiring 100% of the voting interest in Monterey and the issuance of 28 million trust units and 5 million exchangeable shares of Pengrowth Corporation to the former Monterey securityholders.

The trust units and exchangeable shares issued in the Combination were valued at $11.00 per trust unit/exchangeable share based on the closing trading price of the trust units on the date of the Combination. Prior to the Combination, Pengrowth held approximately nine million common shares or approximately 20 percent of the outstanding common shares of Monterey. Under accounting standards for business combinations, Pengrowth was required to fair value its previously held equity investment in Monterey and, as a result, recorded a gain of $73.8 million arising from the difference between the fair value on closing date and the book value of the investment prior to the Combination. The fair value of Pengrowth s previously held equity investment in Monterey was included in the purchase consideration.

Table of Contents

The Combination was accounted for as an acquisition of Monterey by Pengrowth as follows:

Acquired net assets :	
Property, plant and equipment	$ 570,367
Goodwill	55,995
Bank debt	(41,883)
Asset retirement obligations	(12,118)
Working capital deficit	(25,667)
Deferred income taxes	(102,043)
	$ 444,651
Consideration:	
Pengrowth units	$ 307,648
Exchangeable shares	54,939
Fair value of previous equity investment	82,064
	$ 444,651

The estimated fair value of property, plant and equipment was determined using both internal estimates and an independent reserve evaluation. Property, plant and equipment acquired in the Combination included approximately $49 million of producing assets and $521 million of unproven and development properties. The amount of the unproven and development properties was classified as an E&E asset. The deferred income tax liability was determined based on applying Pengrowth s effective deferred income tax rate of approximately 26 percent to the difference between the book and tax basis of the assets acquired. The asset retirement obligations were determined using Pengrowth s estimated costs to remediate, reclaim and abandon the wells and facilities, the estimated timing of the costs to be incurred in future periods, an inflation rate of two percent, and a discount rate of four percent. Transaction costs relating to legal and advisory fees incurred in the Combination of approximately $1.4 million were expensed in 2010 and included in other expenses (income).

Under previous GAAP, ARO was estimated differently, resulting in an increase of $4.2 million to the ARO liability upon adoption of IFRS with a corresponding increase to goodwill. See note 23 for a detailed reconciliation of the comparative period to previous GAAP.

Pengrowth recognized goodwill of approximately $56 million in the Combination (see note 8) representing, in part, the value of establishing a new core area with resource assets in the Montney play. Pengrowth s ability to increase this value beyond what Monterey could realize is partially a result of Pengrowth s ability to fund the development of the necessary capital infrastructure with a lower cost of capital. Goodwill is also impacted by recognizing a deferred tax liability on the acquisition at an undiscounted amount as required by accounting standards. Goodwill is not deductible for tax purposes.

The financial statements include the results of operations and cash flows from Monterey subsequent to the closing date of September 15, 2010. The impact of the Combination on revenue and net income was not material, thus no pro-forma disclosures were required to be presented.

5. OTHER ASSETS

	2011	2010
Remediation trust funds	$ 49,712	$ 42,115
Other investment	35,000	12,000
	$ 84,712	$ 54,115

REMEDIATION TRUST FUNDS

Pengrowth has a contractual obligation to make contributions to a remediation trust fund that is used to cover certain ARO on the Judy Creek properties. Pengrowth makes monthly contributions to the fund of $0.10 per boe of production from the Judy Creek properties and an annual lump sum contribution of $250,000. Every five years, Pengrowth must evaluate the assets in the trust fund and the outstanding ARO, and make recommendations to the former owner of the Judy Creek properties as to whether contribution levels should be changed. The next evaluation is anticipated to occur in 2012. Contributions to the Judy Creek remediation trust

Table of Contents

fund may change based on future evaluations of the fund. The investment in the Judy Creek remediation trust fund is classified as fair value through profit or loss and are recorded at fair value. Interest income is recognized when earned and included in other expenses (income). As at December 31, 2011, the carrying value of the Judy Creek remediation trust fund was $8.2 million (December 31, 2010 $8.7 million).

Pengrowth has a contractual obligation to make contributions to a remediation trust fund that will be used to fund the ARO of the SOEP properties and facilities. Pengrowth currently makes a monthly contribution to the fund of $0.52 per mmbtu of its share of natural gas production and $1.04 per bbl of its share of natural gas liquids production from SOEP. The SOEP remediation trust fund as at December 31, 2011 was $41.5 million (December 31, 2010 $33.4 million). Investment income is recognized when earned and is recorded as other expense (income). The investments in the fund have been designated as fair value through profit or loss and are recorded at fair value.

The following reconciles Pengrowth s investment in remediation trust funds for the periods noted below:

	Remediation Trust Funds	
Balance, January 1, 2010	$	34,821
Contributions		7,019
Remediation expenditures from fund		(696)
Investment income in period		629
Unrealized gain		342
Balance, December 31, 2010	$	42,115
Contributions in period		5,136
Remediation expenditures from fund		(1,095)
Investment income in period		1,989
Unrealized gain		1,567
Balance, December 31, 2011	$	49,712

OTHER INVESTMENT

Pengrowth owns 1.0 million shares of a private corporation with an estimated fair value of $35 million. This investment was designated to be carried at fair value upon adoption of IFRS. The fair value is based in part on the most recent private placement equity offerings closed by the private company. Pengrowth owns a minority interest in and does not have significant influence over the private corporation. As the company is private, the estimated fair value is not based on observable market data and there are restrictions on selling the shares, therefore it is uncertain if Pengrowth could realize this value in an open market and is therefore subject to revision. The fair value has increased to $35 million as at December 31, 2011 (December 31, 2010 $12 million), resulting in a gain of $23 million recognized in other income for the year ended December 31, 2011 (December 31, 2010 NIL).

Table of Contents

6. PROPERTY, PLANT AND EQUIPMENT

Cost or Deemed Cost	Oil and natural gas assets	Other equipment	Total
Balance, January 1, 2010	$ 3,709,913	$ 61,061	$ 3,770,974
Expenditures on property, plant and equipment	283,917	3,625	287,542
Acquisitions through business combinations	49,235		49,235
Property acquisitions	20,171		20,171
Transfers from exploration and evaluation assets	131,039		131,039
Change in asset retirement obligations	(12,478)		(12,478)
Divestitures	(43,295)		(43,295)
Balance, December 31, 2010	$ 4,138,502	$ 64,686	$ 4,203,188
Expenditures on property, plant and equipment	534,297	5,152	539,449
Property acquisitions	10,623		10,623
Transfers from exploration and evaluation assets	26,313		26,313
Change in asset retirement obligations	215,360		215,360
Divestitures	(7,340)		(7,340)
Balance, December 31, 2011	$ 4,917,755	$ 69,838	$ 4,987,593

Accumulated depletion, amortization and impairment losses	Oil and natural gas assets	Other equipment	Total
Balance, January 1, 2010	$	$ 33,790	$ 33,790
Depletion and amortization for the period	424,660	7,721	432,381
Disposals	(999)		(999)
Balance, December 31, 2010	$ 423,661	$ 41,511	$ 465,172
Depletion and amortization for the period	430,053	7,870	437,923
Impairment loss	11,121		11,121
Disposals	(1,057)		(1,057)
Balance, December 31, 2011	$ 863,778	$ 49,381	$ 913,159

Carrying Amount	Oil and natural gas assets	Other equipment	Total
January 1, 2010	$ 3,709,913	$ 27,271	$ 3,737,184
December 31, 2010	3,714,841	23,175	3,738,016
December 31, 2011	4,053,977	20,457	4,074,434

During the year ended December 31, 2011, approximately $15.8 million (December 31, 2010 $12.3 million) of directly attributable general and administrative costs were capitalized.

During the year ended December 31, 2011, approximately $12.6 million of gains were recorded on divestitures (December 31, 2010 $18.4 million).

IMPAIRMENT TESTING

IFRS requires an impairment test to assess the recoverable value of the PP&E within each CGU upon initial adoption and, subsequently, annually or whenever there is an indication of impairment. The recoverable amount of each CGU was based on the higher of value in use or fair value less costs to sell.

Table of Contents

The estimates of fair value less costs to sell was determined based on the following information:

(a) the net present value of each CGUs oil and gas reserves using;

i. proved plus probable reserves estimated by Pengrowth s independent reserves evaluator,

ii. the year end commodity price forecast of our independent reserves evaluator, adjusted for commodity price differentials specific to Pengrowth

iii. discounted at an estimated market rate.

(b) the fair value of undeveloped land.

Key input estimates used in the determination of cash flows from oil and gas reserves include the following:

a) Reserves. Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being restated.

b) Oil and natural gas prices. Forward price estimates of the oil and natural gas prices are used in the cash flow model. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.

c) Discount rate. The discount rate used to calculate the net present value of cash flows is based on estimates of an approximate cost of capital for potential acquirers of Pengrowth or Pengrowth s CGUs. Changes in the general economic environment could result in significant changes to this estimate.

d) Undeveloped land. The undeveloped land value is based on Pengrowth s undeveloped land acreage and the current market prices for undeveloped land.

Impairment tests carried out at December 31, 2011 on each CGU were based on fair value less costs to sell, using a discount rate of eight per cent, an inflation rate of two percent, and the following forward commodity price estimates:

Year	WTI Oil (U.S.$/bbl)	Foreign Exchange Rate (U.S.$/Cdn$)	Edmonton Light Crude Oil (Cdn$/bbl)	AE CO Gas (Cdn$/mmbtu)
2012	$ 97.00	0.980	$ 97.96	$ 3.49
2013	100.00	0.980	101.02	4.13
2014	100.00	0.980	101.02	4.59
2015	100.00	0.980	101.02	5.05
2016	100.00	0.980	101.02	5.51

2017	100.00	0.980	101.02	5.97
2018	101.35	0.980	102.40	6.21
2019	103.38	0.980	104.47	6.33
2020	105.45	0.980	106.58	6.46
2021	107.56	0.980	108.73	6.58
Thereafter	+ 2.0 percent/yr	0.980	+ 2.0 percent/yr	+ 2.0 percent/yr

The carrying value of the producing Groundbirch CGU exceeded the fair value less costs to sell, and an impairment was recognized for approximately $27.4 million. As a result, the full amount of goodwill attributed to the producing Groundbirch CGU was eliminated, thereby reducing goodwill by $16.3 million and the PP&E was reduced by $11.1 million. The impairment of PP&E may be reversed if the fair value of the producing Groundbirch CGU increases in future periods, but the impairment of goodwill attributed to the producing Groundbirch CGU cannot be reversed.

Pengrowth estimated the recoverable amount was greater than the net book value for each CGU at January 1, 2010, upon initial adoption of IFRS, and December 31, 2010, thus no impairment was recognized.

Table of Contents

SENSITIVITY OF RECOVERABLE AMOUNT

As at December 31, 2011, a one percent increase in the assumed discount rate would result in an additional impairment of PP&E of $19.8 million, while there would be no change to the impairment of goodwill attributed to the Groundbirch CGU. A five percent decrease in the forward price estimates would result in an additional impairment of PP&E of $20.2 million, while there would be no change to the impairment of goodwill attributed to the Groundbirch CGU. A one percent decrease in the assumed discount rate would result in no impairment of assets and the impairment of goodwill being reduced by $11.8 million to $4.4 million. A five percent increase in the forward price estimates would result in no impairment of assets and the impairment of goodwill being reduced by $9.0 million.

7. EXPLORATION AND EVALUATION ASSETS

Cost or Deemed Cost		
Balance, January 1, 2010	$	67,597
Additions		53,879
Acquisitions through business combinations		521,132
Transfers to property, plant and equipment		(131,039)
Balance, December 31, 2010	$	511,569
Additions		78,495
Transfers to property, plant and equipment		(26,313)
Balance, December 31, 2011	$	563,751

E&E assets consist of Pengrowth s exploration and development projects which are pending the determination of proved plus probable reserves and production. Additions represent Pengrowth s share of costs incurred on E&E assets during the period. E&E assets consist of costs associated with the Lindbergh Steam Assisted Gravity Drainage (SAGD) project, Horn River and the undeveloped portion of Groundbirch.

Upon achievement of commercial viability and technical feasibility assets are transferred to property, plant and equipment. The amount transferred to property plant and equipment in the year ended December 31, 2011 and 2010 represent the producing sections of the Groundbirch property. The Lindbergh SAGD project is expected to remain in E&E Assets until Pengrowth has achieved technical feasibility and demonstrated commercial viability, including receiving all of the necessary environmental and regulatory approvals. Thus, any production from the Lindbergh SAGD pilot project will not be included in production volumes and any revenue received from production will not be recognized in income while the project remains classified as an E&E Asset.

All of the expenditures on E&E Assets are classified as investing cash flows. All expenditures on E&E assets were capitalized. Liabilities associated with the E&E assets are related to the ARO liabilities of approximately $4.8 million.

During the year ended December 31, 2011, approximately $1.6 million (December 31, 2010 $0.6 million) of directly attributable general and administrative costs were capitalized.

8. GOODWILL

The following table reconciles Pengrowth s Goodwill:

Cost or Deemed Cost		
Balance, January 1, 2010	$	660,896
Acquisitions through business combinations		55,995
Balance, December 31, 2010	$	716,891
Impairment		(16,239)
Balance, December 31, 2011	$	700,652

Goodwill is stated at cost less accumulated impairment. Goodwill is assessed for impairment at each year end, or when there is an indication of impairment, in conjunction with the assessment for impairment of PP&E. At January 1, 2010 and December 31, 2010 there was no impairment of Goodwill. At December 31, 2011 the carrying value of the Groundbirch CGU exceeded the fair value less costs to sell, and an impairment was recognized for approximately $27.4 million. As a result, goodwill attributed to the Groundbirch CGU was reduced by $16.3 million to NIL and the corresponding PP&E was reduced by $11.1 million. The impairment of goodwill attributed to Groundbirch cannot be reversed.

Table of Contents

The carrying value of the remaining goodwill is approximately $701 million. Approximately $130 million is attributable to the Swan Hills area CGU as it relates directly to the purchase of the Carson Creek property in 2006. The remaining goodwill is not attributed to any specific CGU thus this value is supported by the excess recoverable amount over the carrying value of certain of Pengrowth s CGUs.

9. CONVERTIBLE DEBENTURES

On January 14, 2010, Pengrowth redeemed all of the outstanding Convertible Unsecured Subordinated Debentures. The cash redemption amount was approximately $76.8 million, including accrued interest to the redemption date. The debentures bore interest at 6.5% per annum and were convertible at $25.54 per share.

10. LONG TERM DEBT

		2011		2010
U.S. dollar denominated senior unsecured notes:				
50 million at 5.47 percent due April 2013	$	50,799	$	49,638
71.5 million at 4.67 percent due May 2015		72,423		70,731
400 million at 6.35 percent due July 2017		405,429		396,219
265 million at 6.98 percent due August 2018		268,452		262,354
115.5 million at 5.98 percent due May 2020		116,865		114,206
	$	913,968	$	893,148
U.K. Pound Sterling denominated 50 million unsecured notes at 5.46 percent due December 2015		78,718		77,219
Canadian dollar 15 million senior unsecured notes at 6.61 percent due August 2018		15,000		15,000
Canadian dollar revolving credit facility borrowings				39,000
Total long term debt	$	1,007,686	$	1,024,367

Pengrowth s unsecured, covenant based revolving credit facility includes a committed value of $1.0 billion and a $250 million expansion feature providing $1.25 billion of credit capacity subject to the syndicate s participation. The facility matures on November 29, 2015 and can be renewed at Pengrowth s discretion any time prior to its maturity subject to syndicate approval. In the event that the lenders do not agree to a renewal, the outstanding balance is due upon maturity. In conjunction with renewal of this facility in late 2011, Pengrowth incurred fees of $1.6 million which will be amortized to income over the term of the facility.

This facility carries floating interest rates that are expected to range between 2.00 percent and 3.25 percent over bankers acceptance rates, depending on Pengrowth s ratio of senior debt to earnings before interest, taxes and non-cash items. As at December 31, 2011, the facility was undrawn (December 31, 2010 $39 million) and letters of credit in the amount of approximately $24 million (December 31, 2010 $18 million) were outstanding.

Pengrowth also maintains a $50 million demand operating facility with one Canadian bank. As at December 31, 2011, this facility was undrawn (December 31, 2010 $22 million) and letters of credit of approximately $1.5 million (December 31, 2010 $5 million) were outstanding. Borrowings under this facility, as applicable, are included in bank indebtedness on the balance sheet.

As of December 31, 2011, an unrealized cumulative foreign exchange gain of $43 million (December 31, 2010 $63 million gain) has been recognized on the U.S. dollar term notes since the date of issuance. As of December 31, 2011, an unrealized cumulative foreign exchange gain of $35 million (December 31, 2010 $37 million gain) has been recognized on the U.K. Pound Sterling denominated term notes since Pengrowth ceased to designate existing foreign exchange swaps as a hedge on January 1, 2007. See Note 18 for additional information about foreign exchange risk management and the impact on the financial statements.

The five year schedule of long term debt repayment based on current maturity dates and assuming the revolving credit facility is not renewed is as follows: 2012 NIL, 2013 $51 million, 2014 NIL, 2015 $152 million, 2016 NIL.

Table of Contents

11. PROVISIONS

Provisions are comprised of Asset Retirement Obligations (ARO) and contract liabilities (see note 2 for details). The following table reconciles the changes in ARO and contract liabilities:

	Asset retirement obligations	Contract Liabilities	Total
Balance, January 1, 2010	$ 450,611	$ 9,680	$ 460,291
Assumed in business combination	12,117		12,117
Provisions made during the period	12,097		12,097
Provisions on dispositions	(3,284)		(3,284)
Provisions settled	(20,926)		(20,926)
Revisions due to inflation rate changes	(94,797)		(94,797)
Revisions due to discount rate changes	90,854		90,854
Other revisions	(17,348)		(17,348)
Accretion (amortization)	17,744	(1,728)	16,016
Balance, December 31, 2010	$ 447,068	$ 7,952	$ 455,020
Provisions made during the period	7,789		7,789
Provisions on dispositions	(1,151)		(1,151)
Provisions settled	(21,939)		(21,939)
Revisions due to discount rate changes	206,554		206,554
Other revisions	6,932		6,932
Accretion (amortization)	15,618	(1,676)	13,942
Balance, December 31, 2011	$ 660,871	$ 6,276	$ 667,147
As of December 31, 2010			
Current	$ 18,811	$ 1,677	$ 20,488
Non-current	428,257	6,275	434,532
	$ 447,068	$ 7,952	$ 455,020
As of December 31, 2011			
Current	$ 18,500	$ 1,649	$ 20,149
Non-current	642,371	4,627	646,998
	$ 660,871	$ 6,276	$ 667,147

ASSET RETIREMENT OBLIGATIONS (ARO)

Pengrowth has used the following assumptions to estimate the ARO liability as at December 31 for the following years:

	2011	2010
Total escalated future costs ($ millions)	1,845	1,823
Discount rate, per annum	2.5%	3.5%
Inflation rate, per annum	1.5%	1.5%

These costs are expected to be made over 65 years with the majority of the costs incurred between 2036 and 2077.

In 2011, the discount rate used to calculate the ARO was reduced from three and one half percent per annum to three percent per annum in the third quarter to two and one half percent per annum in the fourth quarter to reflect changes to the underlying long term risk free rate. The change in the discount rates was made on a prospective basis with a $207 million increase made to the liability (2010 $91 million) and a corresponding adjustment to PP&E.

Table of Contents

CONTRACT LIABILITIES

Pengrowth assumed firm transportation commitments in conjunction with prior period acquisitions. The fair values of these contracts were estimated on the date of acquisition and the amount recorded is reduced as the contracts settle.

12. INCOME TAXES

A reconciliation of tax expense calculated based on the income before taxes at the statutory tax rate to the actual provision for income taxes is as follows:

	2011	2010
Income before taxes	106,860	321,157
Combined federal and provincial tax rate	26.86%	28.40%
Expected income tax expense	28,703	91,209
Net income of the Trust [1]		(77,590)
Foreign exchange loss (gain) [2]	2,781	(8,320)
Effect of change in corporate tax rate	(10,026)	185,274
Gains on investments	(3,089)	(20,949)
Change in deferred tax asset		(273)
Impairment on assets	4,362	
Other	(403)	1,970
Deferred income tax	22,328	171,321

(1) Relates to distributions of taxable income in Pengrowth Energy Trust for the year ended December 31, 2010 of $273.2 million x 28.40%, where the income tax liability was the responsibility of the trust unit holder.

(2) Reflects the 50% non-taxable portion of foreign exchange gains and losses.

The deferred income tax rate applied to the temporary differences in both 2011 and 2010 was 25.4 percent, compared to the combined federal and provincial statutory rates of 26.9 percent for the 2011 taxation year and 28.4 percent for the 2010 taxation year. The general combined federal and provincial tax rate decreased due to a reduction in the federal rate from 18.0 percent in 2010 to 16.5 percent in 2011.

Under IFRS, taxable temporary differences in the stand alone financial statements of Pengrowth Energy Trust in 2010 were measured using the top marginal personal tax rate of 39 percent, as opposed to the corporate tax rate used under previous GAAP of 25 percent. As Pengrowth Energy Trust had significant unutilized tax pools prior to conversion to a dividend paying corporation on December 31, 2010 this resulted in the recognition of a larger deferred tax asset of approximately $164 million at December 31, 2010 (January 1, 2010 $164 million). The offset to the deferred tax asset was recorded as an adjustment to the opening retained earnings as of January 1, 2010. Upon conversion to a dividend paying corporation on December 31, 2010, this additional deferred tax asset was adjusted to the corporate tax rate of approximately 25 percent and then de-recognized through earnings on December 31, 2010.

The net deferred income tax liability is comprised of:

	2011	2010
Deferred tax liabilities:		
Property, plant and equipment and exploration and evaluation assets	(544,273)	(470,796)
Long term debt	(8,699)	(19,820)
	(552,972)	(490,616)
Less deferred tax assets:		

Non-capital losses	104,194	131,222
Share issue costs	5,106	5,163
Provisions	169,198	107,892
Risk management contracts	16,636	7,645
Net deferred tax liability	(257,838)	(238,694)

Table of Contents

In calculating the deferred income tax liability in 2011, Pengrowth included $420.9 million (2010 $514.4 million) related to non-capital losses available for carry forward to reduce taxable income in future years. These losses expire between 2015 and 2031.

Deferred tax assets have not been recognized with respect to the following items:

	2011	2010
Deductible temporary differences	25,510	25,510
Tax losses	16,711	16,983
	42,221	42,493

A continuity of the net deferred income tax asset (liability) for 2010 and 2011 is detailed in the following tables:

Movement in temporary differences during the year	Balance Jan 1, 2010	Recognized in profit or loss	Recognized directly in equity	Acquired in business combinations	Balance Dec 31, 2010
Property, plant and equipment and exploration and evaluation assets	(271,944)	(96,809)		(102,043)	(470,796)
Long term debt	(12,402)	(7,418)			(19,820)
Share issue costs	9,994	1,416	(6,247)		5,163
Non-capital losses	136,424	(5,202)			131,222
Provisions	171,533	(63,641)			107,892
Risk management contracts	7,312	333			7,645
	40,917	(171,321)	(6,247)	(102,043)	(238,694)

Movement in temporary differences during the year	Balance Jan 1, 2011	Recognized in profit or loss	Recognized directly in equity	Balance Dec 31, 2011
Property, plant and equipment and exploration and evaluation assets	(470,796)	(73,477)		(544,273)
Long term debt	(19,820)	11,121		(8,699)
Share issue costs	5,163	(3,241)	3,184	5,106
Non-capital losses	131,222	(27,028)		104,194
Provisions	107,892	61,306		169,198
Risk management contracts	7,645	8,991		16,636
	(238,694)	(22,328)	3,184	(257,838)

Deferred income tax is a non-cash item relating to the temporary differences between the accounting and tax basis of Pengrowth s assets and liabilities and has no immediate impact on Pengrowth s cash flows.

No current income taxes were paid by Pengrowth in 2011 and 2010.

Table of Contents

13. SHAREHOLDERS CAPITAL

Pengrowth is authorized to issue an unlimited number of common shares and up to 10 million preferred shares. No preferred shares have been issued. Pursuant to a Plan of Arrangement, shareholders capital was reduced by the amount of the consolidated deficit upon conversion to a dividend paying corporation on December 31, 2010.

	2011		2010	
Common Shares	Number of Common Shares	Amount	Number of Common Shares	Amount
Balance, beginning of year	326,024,040	$ 3,171,719		$
Issued to trust unitholders [(1)]			321,910,802	5,270,631
Issued to exchangeable shareholders [(1)]			4,113,238	52,567
Share based compensation (cash exercised)	542,083	3,540		
Share based compensation (non-cash exercised)	368,994	4,546		
Issued for cash under Dividend Reinvestment Plan (DR IP)	5,037,045	54,698		
Issued for cash on equity issue	28,310,000	300,086		
Issue costs net of tax of $3,184		(9,367)		
Elimination of the deficit				(2,151,479)
Balance, end of year	360,282,162	$ 3,525,222	326,024,040	$ 3,171,719

(1) As a result of the conversion to a dividend paying corporation, all outstanding trust units and exchangeable shares were converted to common shares on December 31, 2010.

	2011		2010	
Trust Units Issued	Number of Trust Units	Amount	Number of Trust Units	Amount
Balance, beginning of year		$	289,834,790	$ 4,927,324
Trust unit based compensation (cash exercised)			587,314	3,661
Trust unit based compensation (non-cash exercised)			257,607	3,589
Issued for cash under Distribution Reinvestment Plan (DRIP)			2,282,912	24,072
Issued for the Monterey business combination			27,967,959	307,648
Issued on redemption of Exchangeable shares			980,220	11,339
Issue costs net of tax				(623)
Change in effective tax rate on issue costs (Note 23)				(6,379)
Trust units exchanged for common shares under the Arrangement			(321,910,802)	(5,270,631)
Balance, end of year		$		$

	2011		2010	
Exchangeable Shares	Number of Exchangeable Shares	Amount	Number of Exchangeable Shares	Amount
Balance, beginning of year		$		$
Issued for the Monterey business combination			4,994,426	54,939
				8,967

Redemptions at fair value of trust units or common shares (Note 23)				
Redeemed for trust units		(973,980)		(11,339)
Exchanged for common shares under the Arrangement		(4,020,446)		(52,567)
Balance, end of year	$		$	

Table of Contents

EXCHANGEABLE SHARES

Pengrowth issued exchangeable shares in the Monterey acquisition described in Note 4. These exchangeable shares were classified as a minority interest under IFRS, as opposed to being included in equity under previous GAAP. The exchange ratio increased with each cash distribution and was calculated by multiplying the distribution per trust unit by the opening exchange ratio and dividing by the ten day weighted average trading price of the trust units on the Toronto Stock Exchange prior to the distribution record date.

On December 31, 2010, all outstanding exchangeable shares were exchanged into 1.02308 common shares of the Corporation for each exchangeable share held, thus there was no minority interest as at December 31, 2010.

DIVIDEND REINVESTMENT PLAN

In conjunction with the conversion, Pengrowth revised its Dividend Reinvestment Plan (DRIP). DRIP entitles the shareholder to reinvest cash dividends in additional shares of Pengrowth. Under the revised DRIP, the shares were issued from treasury at a five percent discount to the weighted average closing price of all shares traded on the TSX for the five trading days preceding a dividend payment date.

Previously, the Trust had a similar program where unitholders were entitled to reinvest cash distributions in additional trust units of the Trust. The trust units under this plan were issued from treasury at a five percent discount to the weighted average closing price of all trust units traded on the TSX for the twenty trading days preceding a distribution payment date.

On January 3, 2012, Pengrowth announced that it has introduced a Premium Dividend program in addition to the DRIP, effective February 2012.

14. SHARE BASED COMPENSATION PLANS

Pengrowth has several share based compensation plans. The Long Term Incentive Plan (LTIP) as described below is used to grant awards of share based compensation on or after January 1, 2011. The long term incentive plans that were used prior to conversion to a corporate entity are being phased out with no new awards to be issued under the previous incentive plans. A rolling maximum of four and one half percent of the issued and outstanding common shares, in aggregate, may be reserved for issuance under the share based compensation plans, as approved by shareholders.

LONG TERM INCENTIVE PLAN (LTIP)

Effective January 1, 2011, the following plans under the LTIP were implemented:

(a) Performance Share Units (PSUs)

PSUs entitle the holder to a number of common shares to be issued in the third year after grant. PSUs are awarded to employees, officers and special consultants. The number of shares issued will be subject to a performance factor ranging from zero to two times the aggregate of the number of shares granted plus the amount of reinvested notional dividends.

(b) Restricted Share Units (RSUs)

RSUs are awarded to employees, officers and special consultants and entitle the holder to a number of common shares plus reinvested notional dividends to be issued at vesting over three years. The RSUs generally vest on the first, second and third anniversary date from the date of grant.

(c) Deferred Share Units (DSUs)

The DSU plan is currently only issued to members of the Board of Directors. Each DSU entitles the holder to a number of common shares plus reinvested notional dividends. The DSUs vest upon grant but can only be converted to common shares upon the holder ceasing to be a Director of Pengrowth. The number of common shares ultimately issued will be equal to the number of DSUs initially granted to the holder plus the amount of reinvested notional dividends accruing during the term of the DSUs.

Table of Contents

The Board of Directors retains certain discretion with respect to performance criteria and other aspects of the LTIP.

The following provides a continuity of the LTIP:

	2011					
	PSUs		RSUs		DSUs	
	Number of share units	Weighted average price	Number of share units	Weighted average price	Number of share units	Weighted average price
Outstanding, beginning of year		$		$		$
Granted	637,000	12.44	762,340	12.46	47,468	12.64
Forfeited	(94,249)	12.57	(103,713)	12.57		
Exercised			(9,415)	12.68		
Deemed DR IP (1)	30,523	12.56	36,922	12.57	2,691	12.64
Outstanding, end of year	573,274	$ 12.42	686,134	$ 12.45	50,159	$ 12.64

(1) Weighted average deemed DR IP price is based on the average of the original grant prices.

Compensation expense related to PSU, RSU, and DSU plans are based on the fair value of the share units at the date of grant. The fair value of the performance related share units is determined at the date of grant using the closing share price and is adjusted for the estimated performance multiplier. The amount of compensation expense is reduced by an estimated forfeiture rate at the date of grant, which has been estimated at 10 to 25 percent for employees and 3 to 15 percent for officers, depending on the vesting period. There is no forfeiture rate applied for DSUs as they vest immediately upon grant. For the performance related share plans, the number of shares awarded at the end of the vesting period is subject to certain performance conditions. Fluctuations in compensation expense may occur due to changes in estimating the outcome of the performance conditions. Compensation expense is recognized in income over the vesting period with a corresponding increase or decrease to contributed surplus. Upon the issuance of common shares at the end of the vesting period, shareholders capital is increased and contributed surplus is decreased by the amount of compensation expense incurred during the vesting period. The shares are issued from treasury upon vesting.

Pengrowth recorded $7.2 million of compensation expense in the year ended December 31, 2011 related to the new LTIP units based on the weighted average grant date fair value of $12.46 per share unit (December 31, 2010 NIL). As at December 31, 2011, the amount of compensation expense to be recognized over the remaining vesting period was $8.8 million or $4.86 per share unit subject to the determination of the performance multiplier. The unrecognized compensation cost will be expensed to net income over the remaining weighted average vesting period of 1.2 years.

PREVIOUS LONG TERM INCENTIVE PLAN

(a) Deferred Entitlement Share Units (DESU) Plan (formerly the DEU Plan)

The DESU plan comprises of two types of awards being performance and non-performance related share units. The performance related share units issued to each participant at the end of the three year vesting period will be subject to a performance test which compares Pengrowth s three year average total return to the three year average total return of a peer group of other energy corporations such that upon vesting, the number of shares issued from treasury may range from zero to two times the total of the number of shares granted plus accrued shares through the deemed reinvestment of notional dividends. The non-performance related share units generally vest equally over three years and entitles the holder in each vesting year to one third of the number of common shares initially granted plus the amount of any reinvested notional dividends.

Table of Contents

The following provides a continuity of the DESUs:

DESUs	2011 Number of DESUs	2011 Weighted average price	2010 Number of DESUs	2010 Weighted average price
Outstanding, beginning of year	2,948,588	$ 10.95	2,291,469	$ 12.38
Granted			1,469,536	11.21
Forfeited	(363,889)	9.34	(548,323)	11.12
Exercised	(249,504)	11.14	(459,074)	18.82
Vested, no shares issued (1)	(472,308)	16.81		
Deemed DRIP (2)	161,255	9.99	194,980	11.20
Outstanding, end of year	2,024,142	$ 9.78	2,948,588	$ 10.95
Comprised of:				
Performance related DESUs	1,307,474	$ 8.44	1,957,660	$ 10.47
Non-Performance related DESUs	716,668	12.21	990,928	11.91
Outstanding, end of year	2,024,142	$ 9.78	2,948,588	$ 10.95

(1) 2008 DEU grant vested in 2011 with performance multiplier of zero percent.

(2) Weighted average deemed DR IP price is based on the average of the original grant prices.

Pengrowth recorded $3.6 million of compensation expense in the year ended December 31, 2011 related to the DESUs (December 31, 2010 $3.4 million). As at December 31, 2011, the amount of compensation expense to be recognized over the remaining vesting period was approximately $3.6 million (December 31, 2010 $10.0 million) or $2.21 per DESU (December 31, 2010 $4.26 per DESU), subject to the determination of the performance multiplier. The unrecognized compensation cost will be expensed to net income over the remaining weighted average vesting period of 1.0 year (December 31, 2010 1.6 years).

(b) Common Share Rights Incentive Plan (formerly the Trust Unit Rights Incentive Plan)

The Trust Unit Rights Incentive Plan that was effective under the Trust was renamed on conversion to the Common Share Rights Incentive Plan. This plan consists of two types of awards being share unit options exercisable at a fixed price and share unit rights exercisable at the original grant price or at a reduced price that is calculated in accordance with the plan. The Common Share Rights Incentive Plan provides the holder the right to purchase common shares over a five year period. During the years ended December 31, 2011 and for 2010 there were no exercise price reductions under this plan.

	2011 Number outstanding	2011 Weighted average price	2010 Number outstanding	2010 Weighted average price
Outstanding, beginning of year	3,583,766	$ 12.70	5,455,598	$ 12.23
Granted (1)			30,144	11.22
Expired	(319,174)	19.40	(231,763)	13.31
Forfeited	(505,235)	14.27	(1,082,899)	13.59
Exercised	(542,083)	6.53	(587,314)	6.23
Outstanding, end of year	2,217,274	$ 12.96	3,583,766	$ 12.70

(1) Weighted average exercise price of rights granted are based on the exercise price at the date of grant.

Comprised of:				
Share Unit Options	932,994	$ 6.98	1,646,445	$ 7.02
Share Unit Rights	1,284,280	17.30	1,937,321	17.53
Outstanding, end of year	2,217,274	$ 12.96	3,583,766	12.70
Exercisable, end of year	2,216,221	$ 12.96	3,028,860	$ 13.74

Table of Contents

The following table summarizes information about share unit rights and options outstanding and exercisable at December 31, 2011:

Options Range of exercise prices	Number outstanding	Weighted average remaining contractual life (years)	Weighted average exercise price	Number exercisable	Weighted average exercise price
$6.00 to $8.99	692,708	2.2	$ 6.11	692,708	$ 6.11
$9.00 to $11.99	240,286	2.5	9.52	239,233	9.51
	932,994	2.3	$ 6.98	931,941	$ 6.98

Rights Range of exercise prices	Number outstanding	Weighted average remaining contractual life (years)	Weighted average exercise price	Number exercisable	Weighted average exercise price
$13.00 to $17.99	1,269,406	0.8	$ 17.27	1,269,406	$ 17.27
$18.00 to $25.99	14,874	1.4	19.37	14,874	19.37
	1,284,280	0.8	$ 17.30	1,284,280	$ 17.30

Pengrowth recorded $0.2 million of compensation expense related to the common share rights incentive plan during the year ended December 31, 2011 (December 31, 2010 $1.2 million). As at December 31, 2011, there was no remaining compensation expense to be recognized over the remaining vesting period (December 31, 2010 $0.2 million or $0.04 per share unit right). Common share options were exercised regularly over the year, the weighted average share price over the year ended December 31, 2011 was $11.76 (2010 $11.43).

The total share based compensation expense for the year ended December 31, 2011 was $11.0 million which is comprised of $7.2 million, $3.6 million and $0.2 million related to the new LTIP, DESUs and rights, respectively (2010 $4.6 million comprised of Nil, $3.4 million, and $1.2 million, respectively).

EMPLOYEE SAVINGS PLANS

Pengrowth has savings plans whereby it will match contributions by qualifying employees of one to 12 percent of their annual base salary, less any of Pengrowth s contributions to the Group Registered Retirement Savings Plan (Group RRSP), to purchase shares in the open market. Participants in the Group RRSP can make contributions from one to 12 percent and Pengrowth will match contributions to a maximum of six percent of their annual basic salary. Pengrowth s share of contributions to the Share Purchase Plan and Group RRSP in 2011 were $4.5 million and $1.4 million, respectively (2010 $4.2 million and $1.2 million, respectively).

15. OTHER CASH FLOW DISCLOSURES

RECLASSIFICATIONS

Pengrowth made certain presentation changes under IFRS that differ from previous GAAP. Under IFRS, the amount of cash interest paid is presented as a use of cash in financing activities and hydrocarbon injectant purchases are presented as a use of cash in investing activities. These items were presented as a use of cash in operating activities under previous GAAP (see Note 23).

Table of Contents

CHANGE IN NON-CASH OPERATING WORKING CAPITAL

Cash provided by:	2011	2010
Accounts receivable	$ 8,431	$ 3,590
Accounts payable	10,704	7,473
	$ 19,135	$ 11,063

CHANGE IN NON-CASH INVESTING WORKING CAPITAL

Cash provided by (used for):	2011	2010
Accounts receivable	$ (3,183)	$ 495
Accounts payable, including capital accruals	21,240	17,033
	$ 18,057	$ 17,528

DIVIDENDS PAID

Pengrowth paid $0.07 per share in each of the months January through December 2011, for an aggregate cash dividend of $0.84 per share (December 31, 2010 $0.07 per share per month, aggregate dividend $0.84 per share).

16. AMOUNTS PER SHARE

The following reconciles the weighted average number of shares used in the basic and diluted net income per share calculations:

	2011	2010
Weighted average number of shares basic	332,181,500	299,763,310
Dilutive effect of share based compensation plans	2,655,804	3,628,069
Weighted average number of shares diluted	334,837,304	303,391,379

For the year December 31, 2011, 1.3 million shares (December 31, 2010 2.0 million shares) that are issuable on exercise of the share based compensation plans were excluded from the diluted net income per share calculation as their effect is anti-dilutive.

17. CAPITAL DISCLOSURES

Pengrowth defines its capital as shareholders equity, long term debt, bank indebtedness and working capital.

Pengrowth s goal over longer periods is to maintain or modestly grow production and reserves on a debt adjusted per share basis. Pengrowth seeks to retain sufficient flexibility with its capital to take advantage of acquisition opportunities that may arise.

Pengrowth must comply with certain financial debt covenants. Compliance with these financial covenants is closely monitored by management as part of Pengrowth s overall capital management objectives. The covenants are based on specific definitions prescribed in the debt agreements and are different between the credit facility and the term notes. Throughout the period, Pengrowth was in compliance with all financial covenants.

Management monitors capital using non-GAAP financial metrics, primarily total debt to the trailing twelve months earnings before interest, taxes, depletion, depreciation, amortization, accretion, and other non-cash items (EBITDA) and total debt to total capitalization. Pengrowth seeks to manage the ratio of total debt to trailing EBITDA and total debt to total capitalization ratio with the objective of being able to finance its growth strategy while maintaining sufficient flexibility under the debt covenants. However, there may be instances where it would be acceptable for total debt to trailing EBITDA to temporarily fall outside of the normal targets set by management such as in financing an acquisition to take advantage of growth opportunities. This would be a strategic decision recommended by management and approved by the Board of Directors with steps taken in the subsequent period to restore Pengrowth s capital structure based on its capital management objectives.

In order to maintain its financial condition or adjust its capital structure, Pengrowth may issue new debt, refinance existing debt, issue additional equity, adjust the level of dividends paid to shareholders, adjust the level of capital spending or dispose of non-core assets to reduce debt levels.

Table of Contents

Pengrowth s objectives, policies and processes for managing capital have remained substantially consistent from the prior year. Management believes that current total debt to trailing EBITDA and total debt to total capitalization are within reasonable limits.

The following is a summary of Pengrowth s capital structure, excluding shareholders equity:

		2011		2010
Term credit facilities	$		$	39,000
Senior unsecured notes		1,007,686		985,367
Working capital deficiency		137,287		109,237
	$	1,144,973	$	1,133,604

18. FINANCIAL INSTRUMENTS

Pengrowth s financial instruments are composed of accounts receivable, accounts payable, fair value of risk management assets and liabilities, remediation trust funds, other investments in another entity, dividends payable to shareholders, bank indebtedness and long term debt.

Details of Pengrowth s significant accounting policies for recognition and measurement of financial instruments are disclosed in Note 2.

RISK MANAGEMENT OVERVIEW

Pengrowth has exposure to certain market risks related to volatility in commodity prices, interest rates and foreign exchange rates. Derivative instruments are used to manage exposure to these risks. Pengrowth s policy is not to utilize financial instruments for trading or speculative purposes.

The Board of Directors and management have overall responsibility for the establishment of risk management strategies and objectives. Pengrowth s risk management policies are established to identify the risks faced by Pengrowth, to set appropriate risk limits, and to monitor adherence to risk limits. Risk management policies are reviewed regularly to reflect changes in market conditions and Pengrowth s activities.

MARKET RISK

Market risk is the risk that the fair value, or future cash flows of financial assets and liabilities, will fluctuate due to movements in market prices. Market risk is composed of commodity price risk, foreign currency risk and interest rate risk.

Commodity Price Risk

Pengrowth is exposed to commodity price risk as prices for oil and gas products fluctuate in response to many factors including local and global supply and demand, weather patterns, pipeline transportation, political stability and economic factors. Commodity price fluctuations are an inherent part of the oil and gas business. While Pengrowth does not consider it prudent to entirely eliminate this risk, it does mitigate some of the exposure to commodity price risk to protect the return on acquisitions and provide a level of stability to operating cash flow which enables Pengrowth to fund its capital development program and dividends. Pengrowth utilizes financial contracts to fix the commodity price associated with a portion of its future production. The use of forward and futures contracts are governed by formal policies and is subject to limits established by the Board of Directors. The Board of Directors and management may re-evaluate these limits as needed in response to specific events such as market activity, additional leverage, acquisitions or other transactions where Pengrowth s capital structure may be subject to more risk from commodity prices.

As at December 31, 2011, Pengrowth had fixed the price applicable to future production as follows:

Crude Oil:

Reference Point	Volume (bbl/d)	Term	Price per bbl
Financial:			

WTI [1]	17,000	Jan 1, 2012 - Dec 31, 2012	$ 93.23	Cdn
WTI [1]	3,500	Jan 1, 2013 - Dec 31, 2013	$ 95.29	Cdn

[1] Associated Cdn $/U.S. $ foreign exchange rate has been fixed.

Table of Contents

Natural Gas:				
Reference Point	Volume (MMbtu/d)	Term	Price per MMbtu	
Financial:				
AECO	14,217	Jan 1, 2012 - Dec 31, 2012	$ 4.45	Cdn

Commodity Price Sensitivity

Each Cdn $1 per barrel change in future oil prices would result in approximately Cdn $7.5 million pre-tax change in the unrealized gain (loss) on commodity risk management contracts as at December 31, 2011 (December 31, 2010 $6.2 million). Similarly, each Cdn $0.25 per MMbtu change in future natural gas prices would result in approximately Cdn $1.3 million pre-tax change in the unrealized gain (loss) on commodity risk management contracts (December 31, 2010 $4.6 million).

As of close December 31, 2011, the AECO spot price gas price was approximately $2.61 per MMbtu (December 31, 2010 $4.05 per MMbtu), the WTI prompt month price was U.S. $98.83 per barrel (December 31, 2010 U.S. $91.38 per barrel).

Power Price Risk

As at December 31, 2011, Pengrowth had fixed the price applicable to future power costs as follows:

Power:				
Reference Point	Volume (MW)	Term	Price per MW	
Financial:				
AESO	15	Jan 1, 2012 - Dec 31, 2012	$ 72.83	Cdn
AESO	5	Jan 1, 2013 - Dec 31, 2013	$ 74.50	Cdn

As of close December 31, 2011, the Alberta average power pool spot price was approximately $45.44/MW (December 31, 2010 $26.99/MW). The average Alberta power pool price was $76.21/MW for the year ended December 31, 2011 (December 31, 2010 $50.88/MW).

Power Price Sensitivity

Each Cdn $1 per MW change in future power prices would result in approximately Cdn $0.2 million pre-tax change in the unrealized gain (loss) on power risk management contracts as at December 31, 2011 (December 31,2010 $0.2 million).

Foreign Exchange Risk

Pengrowth is exposed to foreign currency fluctuations as crude oil and natural gas prices received are referenced to U.S. dollar denominated prices. Pengrowth has mitigated some of this exchange risk by entering into fixed Canadian dollar crude oil and natural gas price swaps as outlined in the commodity price risk section above.

Pengrowth is exposed to foreign currency fluctuation on the U.S. dollar denominated notes for both interest and principal payments. Pengrowth has not entered into any contracts to mitigate the foreign exchange risk associated with the U.S. dollar denominated term notes as the U.S. dollar denominated interest payments partially offset U.S. dollar denominated revenues.

Pengrowth entered into foreign exchange risk management contracts in conjunction with issuing U.K. Pounds Sterling 50 million ten year term notes which fixed the Canadian dollar to U.K. Pound Sterling exchange rate on the interest and principal of the U.K. Pound Sterling denominated debt at approximately 0.4976 U.K. Pounds Sterling per Canadian dollar.

Table of Contents

Foreign Exchange Rate Sensitivity

The following summarizes the sensitivity on a pre-tax basis of a change in the foreign exchange rate on unrealized foreign exchange gains (losses) related to the translation of the foreign denominated term debt and on unrealized gains (losses) related to the change in the fair value of the foreign exchange risk management contracts, holding all other variables constant:

	Cdn $0.01 Exchange Rate Change	
Foreign Exchange Sensitivity as at December 31, 2011	Cdn - U.S.	Cdn - U.K.
Unrealized foreign exchange gain or loss on foreign denominated debt	$ 9,020	$ 500
Unrealized foreign exchange risk management gain or loss		593

	Cdn $0.01 Exchange Rate Change	
Foreign Exchange Sensitivity as at December 31, 2010	Cdn - U.S.	Cdn - U.K.
Unrealized foreign exchange gain or loss on foreign denominated debt	$ 9,020	$ 500
Unrealized foreign exchange risk management gain or loss		578

Interest Rate Risk

Pengrowth is exposed to interest rate risk on the Canadian dollar revolving credit facility as the interest is based on floating interest rates.

Interest Rate Sensitivity

As at December 31, 2011, Pengrowth has approximately $1.0 billion of long term debt (December 31, 2010 $1.0 billion) with no amounts outstanding which are based on floating interest rates (December 31, 2010 $39 million). A one percent increase in interest rates would have no impact on 2011 pre-tax interest expense (2010 $0.4 million increase).

Summary of Risk Management Contracts

Pengrowth s risk management contracts are recorded on the balance sheet at their estimated fair value and split between current and non-current assets and liabilities on a contract by contract bases. Realized and unrealized gains and losses are included in the Statement of Income.

The following tables provide details of the fair value of risk management contracts and the unrealized and realized gains and losses on risk management recorded in the Statement of Income:

As at and for the year ended December 31, 2011	Commodity risk management contracts [1]	Power risk management contracts [2]	Foreign exchange risk management contracts [3]	Total
Current portion of risk management assets	$	$ 643	$	$ 643
Current portion of risk management liabilities	(38,574)		(1,179)	(39,753)
Non-current portion of risk management liabilities	(3,462)	(107)	(22,918)	(26,487)
Risk management assets (liabilities), end of year	(42,036)	536	(24,097)	(65,597)
Less: Risk management (liabilities) assets at beginning of year	(2,085)	870	(25,929)	(27,144)
Unrealized (loss) gain on risk management contracts for the year	(39,951)	(334)	1,832	(38,453)
Realized gain (loss) on risk management contracts for the year	16,843	6,543	(593)	22,793
	$ (23,108)	$ 6,209	$ 1,239	$ (15,660)

Total unrealized and realized (loss) gain on risk management contracts for the year

Table of Contents

As at and for the year ended December 31, 2010	Commodity risk management contracts [1]	Power risk management contracts [2]	Foreign exchange risk management contracts [3]	Total
Current portion of risk management assets (liabilities)	$ 12,680	$ 870	$	$ 13,550
Current portion of risk management liabilities	(8,029)		(1,249)	(9,278)
Non-current portion of risk management liabilities	(6,736)		(24,680)	(31,416)
Risk management assets (liabilities), end of year	(2,085)	870	(25,929)	(27,144)
Less: Risk management (liabilities) assets at beginning of year	(9,034)		(17,789)	(26,823)
Unrealized gain (loss) on risk management contracts for the year	6,949	870	(8,140)	(321)
Realized gain (loss) on risk management contracts for the year	75,065	565	(586)	75,044
Total unrealized and realized gain (loss) on risk management contracts for the year	$ 82,014	$ 1,435	$ (8,726)	$ 74,723

(1) Unrealized gains and losses are presented as a separate caption in revenue. Realized gains and losses are included in oil and gas sales.

(2) Unrealized gains and losses are included in other expenses (income). Realized gains and losses are included in operating expenses.

(3) Unrealized gains and losses are presented as a separate caption in expenses. Realized gains and losses are included in interest expense.

FAIR VALUE

The fair value of accounts receivable, accounts payable, bank indebtedness, and dividends payable approximate their carrying amount due to the short-term nature of those instruments. The fair value of the Canadian dollar revolving credit facility is equal to its carrying amount as the facility bears interest at floating rates and credit spreads within the facility are indicative of market rates. The fair value of the remediation trust funds and investment in a private company are equal to their carrying amount as these assets are classified as fair value through profit or loss and carried at fair value.

The following tables provide fair value measurement information for financial assets and liabilities as of December 31, 2011 and 2010.

			Fair Value Measurements Using:		
As at December 31, 2011	Carrying Amount	Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Financial Assets					
Remediation trust funds	$ 49,712	$ 49,712	$ 49,712	$	$
Fair value of risk management contracts	643	643		643	
Investment in Private Corporation	35,000	35,000			35,000
Financial Liabilities					
U.S. dollar denominated senior unsecured notes	913,968	1,075,196		1,075,196	
Cdn dollar senior unsecured notes	15,000	16,836		16,836	
U.K. Pound Sterling denominated unsecured notes	78,718	89,786		89,786	
Fair value of risk management contracts	66,240	66,240		66,240	

Table of Contents

			Fair Value Measurements Using:		
As at December 31, 2010	Carrying Amount	Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Financial Assets					
Remediation trust funds	$ 42,114	$ 42,115	$ 42,115	$	$
Fair value of risk management contracts	13,550	13,550		13,550	
Investment in Private Corporation	12,000	12,000			12,000
Financial Liabilities					
U.S. dollar denominated senior unsecured notes	893,148	988,949		988,949	
Cdn dollar senior unsecured notes	15,000	15,735		15,735	
U.K. Pound Sterling denominated unsecured notes	77,219	84,599		84,599	
Fair value of risk management contracts	40,694	40,694		40,694	

Level 1 Fair Value Measurements

Financial assets and liabilities are recorded at fair value based on quoted prices in active markets.

Level 2 Fair Value Measurements

Risk management contracts the fair value of the risk management contracts is based on commodity and foreign exchange curves that are readily available or, in their absence, third-party market indications and forecasts priced on the last trading day of the applicable period.

Term notes the fair value of the term notes is determined based on the risk free interest rate on government debt instruments of similar maturities, adjusted for estimated credit risk, industry risk and market risk premiums.

Level 3 Fair Value Measurements

Investment in Private Corporation the fair value of the investment in Private Corporation is determined by considering several factors, particularly the issue price of the shares in the most recent private placement. The fair value of the investment has increased to $35 million as at December 31, 2011 (December 31, 2010 $12 million), resulting in an unrealized gain of $23 million in 2011 (December 31, 2010 NIL).

CREDIT RISK

Credit risk is the risk of financial loss to Pengrowth if a counterparty to a financial instrument fails to meet its contractual obligations. A significant portion of Pengrowth s accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. Uncertainty in the credit markets, should it exist, may restrict the ability of Pengrowth s normal business counterparties to meet their obligations to Pengrowth. Additional credit risk could exist where little or none previously existed. Pengrowth manages its credit risk by performing a credit review on each marketing counterparty and following a credit practice that limits transactions according to the counterparty s credit rating as assessed by Pengrowth. In addition, Pengrowth may require letters of credit or parental guarantees from certain counterparties to mitigate some of the credit risk associated with the amounts owing by the counterparty. The use of financial swap agreements involves a degree of credit risk that Pengrowth manages through its credit policies which are designed to limit eligible counterparties to those with investment grade credit ratings or better. The carrying value of accounts receivable and risk management assets represents Pengrowth s maximum credit exposure.

Pengrowth sells a significant portion of its oil and gas to a limited number of counterparties. Pengrowth has three counterparties that individually account for more than ten percent of annual revenue. All of these counterparties are large, well-established companies supported by investment grade credit ratings.

Table of Contents

Pengrowth considers amounts over 90 days as past due. As at December 31, 2011, the amount of accounts receivable that were past due was not significant. Pengrowth has not recorded a significant allowance for doubtful accounts during 2011 and 2010 and has no significant bad debt provision at December 31, 2011. Pengrowth s objectives, processes and policies for managing credit risk have not changed from the previous year.

The components of accounts receivable are as follows:

	2011	2010
Trade	$ 163,977	$ 170,702
Prepaid and other	19,837	18,914
	$ 183,814	$ 189,616

LIQUIDITY RISK

Liquidity risk is the risk that Pengrowth will not be able to meet its financial obligations as they fall due. Pengrowth s approach to managing liquidity is to ensure, as much as possible, that it will always have sufficient liquidity to meet its liabilities when due, under normal and stressed conditions. Management closely monitors cash flow requirements to ensure that it has sufficient cash on demand or borrowing capacity to meet operational and financial obligations over the next three years. Pengrowth maintains a committed $1.0 billion term credit facility with an additional $250 million available under an expansion feature subject to lender approval and a $50 million demand operating line of credit. Pengrowth s long term notes and bank credit facilities are unsecured and equally ranked.

All of Pengrowth s financial liabilities are current and due within one year, except as follows:

As at December 31, 2011	Carrying Amount	Contractual Cash Flows	Within 1 year	1-2 years	2-5 years	More than 5 years
Cdn dollar senior unsecured notes[1]	$ 15,000	$ 21,585	$ 992	$ 992	$ 2,977	$ 16,624
U.S. dollar denominated senior unsecured notes [1]	913,968	1,259,950	57,844	106,774	232,500	862,832
U.K. Pound Sterling denominated unsecured notes [1]	78,718	95,893	4,313	4,313	87,267	-
Remediation trust fund payments		12,500	250	250	750	11,250
Commodity risk management contracts						
Power risk management contracts						
Commodity risk management contracts	3,462	3,511		3,511		
Power risk management contracts	107	110		110		
Foreign exchange risk management contracts	22,918	135	30	30	75	

(1) Contractual cash flows include future interest payments calculated at period end exchange rates and interest rates except for term notes which are calculated at the actual interest rate.

As at December 31, 2010	Carrying Amount	Contractual Cash Flows	Within 1 year	1-2 years	2-5 years	More than 5 years
Cdn dollar revolving credit facility [1]	$ 39,000	$ 42,644	$ 1,289	$ 1,289	$ 40,066	$
Cdn dollar senior unsecured notes [1]	15,000	22,578	992	992	2,975	17,619
U.S. dollar denominated senior unsecured notes [1]	893,148	1,288,764	56,571	56,571	281,108	894,514
U.K. Pound Sterling denominated unsecured notes [1]	77,219	98,393	4,235	4,235	89,923	
Remediation trust fund payments		12,500	250	250	750	11,250

Commodity risk management contracts	6,736	6,911		6,911	
Foreign exchange risk management contracts	24,680	150	30	30	90

(1) Contractual cash flows include future interest payments calculated at period end exchange rates and interest rates except for term notes which are calculated at the actual interest rate.

Table of Contents

19. FOREIGN EXCHANGE (GAIN) LOSS

	2011	2010
Unrealized foreign exchange loss (gain) on U.S. dollar denominated debt	$ 19,553	$ (50,692)
Unrealized foreign exchange loss (gain) on U.K. pound sterling denominated debt	1,377	(7,366)
	$ 20,930	$ (58,058)
Unrealized (gain) loss on foreign exchange risk management contracts	(1,832)	8,140
Unrealized foreign exchange loss (gain)	$ 19,098	$ (49,918)
Realized foreign exchange loss	$ 1,583	$ 2,061

20. COMMITMENTS

	2012	2013	2014	2015	2016	Thereafter	Total
Long term debt [1]	$	$ 50,850	$	$ 151,711	$	$ 808,769	$ 1,011,330
Interest payments on long term debt [2]	63,149	61,229	60,371	58,002	52,660	70,687	366,098
Operating leases [3]	15,732	15,445	14,994	14,211	14,003	15,911	90,296
	$ 78,881	$ 127,524	$ 75,365	$ 223,924	$ 66,663	$ 895,367	$ 1,467,724
Purchase obligations							
Pipeline transportation	28,527	22,473	19,395	17,535	2,113	506	90,549
CO_2 purchases [4]	2,874	2,891	2,907	2,924	836		12,432
	$ 31,401	$ 25,364	$ 22,302	$ 20,459	$ 2,949	$ 506	$ 102,981
Remediation trust fund payments	250	250	250	250	250	11,250	12,500
	$ 110,532	$ 153,138	$ 97,917	$ 244,633	$ 69,862	$ 907,123	$ 1,583,205

(1) The debt repayment includes the principal owing at maturity on foreign denominated fixed rate debt translated using the year end exchange rate.

(2) Interest payments are calculated at period end exchange rates and interest rates except for foreign denominated fixed rate debt which is calculated at the actual interest rate.

(3) Includes office rent and vehicle leases.

(4) For the Weyburn CO_2 project, prices are denominated in U.S. dollars and have been translated at the year-end exchange rate.

21. CONTINGENCIES

Pengrowth is sometimes named as a defendant in litigation. The nature of these claims is usually related to settlement of normal operational issues and labour issues. The outcome of such claims against Pengrowth is not determinable at this time; however, their ultimate resolution is not expected to have a materially adverse effect on Pengrowth as a whole.

22. SUPPLEMENTARY DISCLOSURES

INCOME STATEMENT PRESENTATION

Pengrowth s statement of income is prepared primarily by the nature of expense, with the exception of employee compensation costs which are included in both operating and general and administrative expense line items.

The following table details the amount of total employee compensation costs included in the operating and general and administrative expense line items in the statement of income.

	2011	2010
Operating	$ 54,382	$ 54,142
General and administrative	38,908	27,852
Total employee compensation costs	$ 93,290	$ 81,994

Table of Contents

KEY MANAGEMENT PERSONNEL

Pengrowth has determined that the key management personnel of the Corporation consists of its officers and directors. In addition to the officers salaries and directors fees, the Company also provides other compensation to both groups including the LTIP.

The following table provides information on compensation expense related to officers and directors. Thirteen officers and seven non-executive directors comprised the key management personnel at Pengrowth during the course of the year ended December 31, 2011 (2010 seventeen officers and nine non-executive directors).

Year ended December 31, 2011	Wages & Benefits	Bonus and other compensation	Share based Compensation Expense	Severance	Total
Directors	$ 615	$	$ 600	$	$ 1,215
Officers	4,170	1,378	2,615	1,102	9,265
	$ 4,785	$ 1,378	$ 3,215	$ 1,102	$ 10,480

Year ended December 31, 2010	Wages & Benefits	Bonus and other compensation	Share based Compensation Expense	Severance	Total
Directors	$ 724	$	$ 867	$	$ 1,591
Officers	3,907	1,045	1,486	1,840	8,278
	$ 4,631	$ 1,045	$ 2,353	$ 1,840	$ 9,869

Table of Contents

23. RECONCILIATION FROM PREVIOUS GAAP TO IFRS

RECONCILIATION OF BALANCE SHEET FROM PREVIOUS GAAP TO IFRS

AT THE DATE OF IFRS TRANSITION JANUARY 1, 2010

	Note	Previous GAAP	Reclassification upon transition to IFRS	Effect of transition to IFRS	IFRS
ASSETS					
Current Assets					
Accounts receivable		$ 182,342	$	$	$ 182,342
Fair value of risk management contracts		14,001			14,001
Future income taxes	(e)	969	(969)		
		197,312	(969)		196,343
Other assets	(d)	46,027		6,984	53,011
Deferred income taxes	(e)		(180,671)	221,588	40,917
Property, plant and equipment	(a)	3,789,369	(67,597)	15,412	3,737,184
Exploration and evaluation assets	(a)		67,597		67,597
Goodwill	(c)	660,896			660,896
TOTAL ASSETS		$ 4,693,604	$ (181,640)	$ 243,984	$ 4,755,948
LIABILITIES AND UNITHOLDERS EQUITY					
Current Liabilities					
Bank indebtedness		$ 11,563	$	$	$ 11,563
Accounts payable		185,337			185,337
Distributions payable to unitholders		40,590			40,590
Fair value of risk management contracts		17,555			17,555
Contract liabilities	(b)	1,728	(1,728)		
Current portion of long-term debt		157,546			157,546
Current portion of provisions	(b)		21,227		21,227
		414,319	19,499		433,818
Fair value of risk management contracts		23,269			23,269
Contract liabilities	(b)	7,952	(7,952)		
Convertible debentures		74,828			74,828
Long term debt		907,599			907,599
Provisions	(b)		277,249	161,815	439,064
Asset retirement obligations	(b)	288,796	(288,796)		
Future income taxes	(e)	181,640	(181,640)		
		1,898,403	(181,640)	161,815	1,878,578
Trust Unitholders Equity					
Trust unitholders capital	(f)	4,920,945		6,379	4,927,324
Equity portion of convertible debentures		160			160
Contributed surplus		18,617			18,617
Deficit	(f)	(2,144,521)		75,790	(2,068,731)
		2,795,201		82,169	2,877,370
TOTAL LIABILITIES AND UNITHOLDERS EQUITY		$ 4,693,604	$ (181,640)	$ 243,984	$ 4,755,948

Table of Contents

23. RECONCILIATION FROM PREVIOUS GAAP TO IFRS (continued)

RECONCILIATION OF BALANCE SHEET FROM PREVIOUS GAAP TO IFRS

AS AT DECEMBER 31, 2010

	Note	Previous GAAP	Reclassification upon transition to IFRS	Effect of transition to IFRS	IFRS
ASSETS					
Current Assets					
Cash and cash equivalents		$ 2,849	$	$	$ 2,849
Accounts receivable		189,616			189,616
Fair value of risk management contracts		13,550			13,550
		206,015			206,015
Other assets	(d)	47,114		7,001	54,115
Property, plant and equipment	(a)	4,076,976	(511,569)	172,609	3,738,016
Exploration and evaluation assets	(a)		511,569		511,569
Goodwill	(c)	712,661		4,230	716,891
TOTAL ASSETS		$ 5,042,766	$	$ 183,840	$ 5,226,606
LIABILITIES AND SHAREHOLDERS EQUITY					
Current Liabilities					
Bank indebtedness		$ 22,000	$	$	$ 22,000
Accounts payable		240,952			240,952
Dividends payable		22,534			22,534
Fair value of risk management contracts		9,278			9,278
Future income taxes		1,203	(1,203)		
Contract liabilities	(b)	1,677	(1,677)		
Current portion of provisions	(b)		20,488		20,488
		297,644	17,608		315,252
Fair value of risk management contracts		31,416			31,416
Contract liabilities	(b)	6,275	(6,275)		
Long term debt		1,024,367			1,024,367
Asset retirement obligations		259,538	(259,538)		
Provisions	(b)		247,002	187,530	434,532
Deferred income taxes	(e)		237,753	941	238,694
Future income taxes	(e)	236,550	(236,550)		
		$ 1,855,790	$	$ 188,471	$ 2,044,261
SHAREHOLDERS EQUITY					
Shareholders capital	(f)	3,167,383	(4,631)	8,967	3,171,719
Contributed surplus		19,593		(8,967)	10,626
Deficit	(f)		4,631	(4,631)	
		3,186,976		(4,631)	3,182,345
TOTAL LIABILITIES AND SHAREHOLDERS EQUITY		$ 5,042,766	$	$ 183,840	$ 5,226,606

Table of Contents

23. RECONCILIATION FROM PREVIOUS GAAP TO IFRS (continued)

RECONCILIATION OF STATEMENT OF INCOME FROM PREVIOUS GAAP TO IFRS

YEAR ENDED DECEMBER 31, 2010

	Note	Previous GAAP	Reclassification upon transition to IFRS	Effect of transition to IFRS	IFRS
REVENUES					
Oil and gas sales		$ 1,353,283	$ 15,430	$	$ 1,368,713
Royalties, net of incentives		(252,699)			(252,699)
		1,100,584	15,430		1,116,014
Unrealized (loss) gain on commodity risk management		6,949			6,949
Processing and other income		20,598	(20,598)		
		1,128,131	(5,168)		1,122,963
EXPENSES					
Operating		371,716	(14,538)		357,178
Transportation		15,739	9,370		25,109
Amortization of injectants for miscible floods	(g)	15,056	(15,056)		
Interest and financing charges	(g)	70,464	(70,464)		
General and administrative	(g)	50,894			50,894
Realized foreign exchange loss (gain)	(g)	2,061	(2,061)		
Unrealized foreign exchange loss (gain)	(g)	(49,918)	49,918		
Depletion, depreciation and amortization	(a) (g)	529,396	15,056	(112,071)	432,381
Accretion	(g)	22,960	(22,960)		
Gain on equity investment	(g)	(73,756)	73,756		
Other expenses (income)	(g)	(11,909)	11,909		
		942,703	34,930	(112,071)	865,562
OPERATING INCOME (LOSS)		185,428	(40,098)	112,071	257,401
Other (income) expense items					
Gain on equity investment	(g)		(73,756)		(73,756)
Gain on disposition of properties	(a)			(18,425)	(18,425)
Unrealized foreign exchange (gain)	(g)		(49,918)		(49,918)
Realized foreign exchange loss	(g)		2,061		2,061
Interest and financing charges	(g)		70,464		70,464
Accretion	(g)		22,960	(5,216)	17,744
Other (income) expense	(g)		(11,909)	(17)	(11,926)
			(40,098)	(23,658)	(63,756)
INCOME BEFORE TAXES		185,428		135,729	321,157
Future income tax (reduction) expense		(44,829)		216,150	171,321
NET INCOME AND COMPREHENSIVE INCOME		$ 230,257	$	$ (80,421)	$ 149,836
Deficit, beginning of year		(2,144,521)		75,790	(2,068,731)
Distributions declared		(232,584)			(232,584)
Elimination of deficit		2,146,848		4,631	2,151,479
DEFICIT, END OF YEAR		$	$	$	$
Net income per share					
Basic		$ 0.76			$ 0.50
Diluted		$ 0.76			$ 0.49

Table of Contents

23. RECONCILIATION FROM PREVIOUS GAAP TO IFRS (continued)

RECONCILIATION OF STATEMENT OF CASH FLOWS FROM PREVIOUS GAAP TO IFRS

YEAR ENDED DECEMBER 31, 2010

	Note	Previous GAAP	Reclassification upon transition to IFRS	Effect of transition to IFRS	IFRS
CASH PROVIDED BY (USED FOR):					
OPERATING					
Net income and comprehensive income		$ 230,257	$	$ (80,421)	$ 149,836
Depletion, depreciation and accretion	(a) (g)	552,356	15,056	(117,287)	450,125
Amortization of injectants	(g)	15,056	(15,056)		
Purchase of injectants		(9,324)	9,324		
Deferred income tax reduction	(e)	(44,829)		216,150	171,321
Contract liability amortization		(1,728)			(1,728)
Unrealized foreign exchange (gain) loss	(g)	(49,918)			(49,918)
Unrealized (gain) loss on commodity risk management	(g)	(6,949)			(6,949)
Share based compensation		4,565			4,565
Gain on sale of assets	(a)			(18,425)	(18,425)
Non-cash gain on equity investment		(73,756)			(73,756)
Other items		1,192		(17)	1,175
Funds flow from operations		616,922	9,324		626,246
Interest and financing charges			70,464		70,464
Expenditures on remediation		(20,926)			(20,926)
Changes in non-cash operating working capital		9,999	1,064		11,063
		605,995	80,852		686,847
FINANCING					
Distributions paid		(250,640)			(250,640)
Bank indebtedness		10,437			10,437
Redemption of convertible debentures		(76,610)			(76,610)
Long term debt increase (decrease)		(24,581)			(24,581)
Interest paid	(g)		(71,528)		(71,528)
Proceeds from equity issues		26,980			26,980
Other financing costs		(3,110)			(3,110)
		(317,524)	(71,528)		(389,052)
INVESTING					
Capital expenditures		(333,842)			(333,842)
Other property acquisitions		(20,171)			(20,171)
Proceeds on property dispositions		60,721			60,721
Purchase of injectants			(9,324)		(9,324)
Other investments		(2,906)			(2,906)
Change in remediation trust funds		(6,952)			(6,952)
Change in non-cash investing working capital		17,528			17,528
		(285,622)	(9,324)		(294,946)
CHANGE IN CASH AND CASH EQUIVALENTS		2,849			2,849
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR					
CASH AND CASH EQUIVALENTS AT END OF YEAR		$ 2,849	$	$	$ 2,849

Table of Contents

23. RECONCILIATION FROM PREVIOUS GAAP TO IFRS (continued)

Notes to reconciliations

(a) Property, Plant and Equipment and Exploration and Evaluation Assets

IFRS 1 election for full cost oil and gas entities

Pengrowth elected to utilize an IFRS 1 exemption whereby the full cost pool using previous GAAP was measured upon transition to IFRS as follows:

(i) E&E assets were reclassified from the full cost pool to E&E assets at the amount that was recorded under previous GAAP; and

(ii) The remaining full cost pool was allocated to the producing/development assets and components pro rata using total proved plus probable reserve values at January 1, 2010.

This resulted in a $68 million at January 1, 2010 (December 31, 2010 $512 million) increase in E&E assets with a corresponding decrease in PP&E, with no impact on deferred taxes. The increase in E&E assets during 2010 is due to capitalization of ongoing exploration and evaluation expenditures and the acquisition of significant E&E assets in the Monterey acquisition in the third quarter of 2010.

Depletion

Under IFRS, depletion is calculated on a unit of production basis using total proved plus probable reserves as compared to total proved reserves under previous GAAP. As a result of this change, the depletion expense decreased by approximately $112 million for the year ended December 31, 2010.

Gains on disposition

Pengrowth recorded a gain on disposition of approximately $18 million for the year ended December 31, 2010. Of this, disposition of non-core properties accounted for approximately $15 million for the year ended December 31, 2010. The remaining gain on disposition of approximately $3 million for the year ended December 31, 2010 relate to asset swaps.

Gain on Equity Investment

Under the IFRS accounting standards for business combinations adopted on January 1, 2010, Pengrowth was required to fair value its previously held equity investment in Monterey and, as a result, recorded a gain of $73.8 million arising from the difference between the fair value and the book value of the investment prior to the Combination. The fair value of Pengrowth s previously held equity investment in Monterey was included in the purchase consideration.

Other

The IFRS opening balance sheet at January 1, 2010 was adjusted to correct for an immaterial amount related to previously expensed general and administrative costs and operating costs that should have been capitalized. This resulted in an increase of $15.4 million to PP&E over the amount recorded under previous GAAP as at January 1, 2010.

Table of Contents

23. RECONCILIATION FROM PREVIOUS GAAP TO IFRS (continued)

The following summarized the change to PP&E and the related effect on the deficit, net of tax, as a result of adopting IFRS:

	As at January 1, 2010	As at December 31, 2010
Increase to property, plant and equipment due to:		
Costs previously expensed	$ 15,412	$ 15,412
Gain on dispositions		18,425
Depletion		112,071
Changes in asset retirement obligations		26,701
	15,412	172,609
Amounts not affecting deficit		
Changes in asset retirement obligations		(26,701)
	15,412	145,908
Tax Effect	(4,403)	(38,313)
Decrease to deficit	$ 11,009	$ 107,595

Reclassification of E&E assets from PP&E under previous GAAP can be summarized as follows:

	As at January 1, 2010	As at December 31, 2010
Decrease to Property Plant and Equipment	$ (67,597)	$ (511,569)
Tax Effect		
Increase to exploration and evaluation assets	$ 67,597	$ 511,569

Net income increased approximately $97 million for the year ended December 31, 2010 as a result of these changes, as follows:

	Year ended December 31, 2010
Increase to net income due to:	
Gain on dispositions	$ 18,425
Depletion	112,071
	$ 130,496
Tax Effect	(33,910)
Increase to net income	$ 96,586

(b) Provisions

Under IFRS, contract liabilities and ARO are classified as provisions.

Accounting for contract liabilities remains unchanged under IFRS.

ARO is calculated using a risk free discount rate of four percent and an inflation rate of two percent under IFRS, at January 1, 2010 (December 31, 2010 three and one-half percent discount rate and one and one-half percent inflation rate) as compared to a credit adjusted risk free rate of eight percent and a two percent inflation rate under previous GAAP. The effect of using a risk free discount rate of four percent resulted in an increase of $360 million to the ARO liability which was partially offset by changes to timing and cost estimates of $198 million on transition to IFRS. Due to the use of the aforementioned IFRS 1 election for full cost oil and gas entities, the offset to the increase to the ARO is required to be recognized directly in the opening deficit at the date of transition.

In the third quarter of 2010, the inflation rate used to calculate the ARO was reduced from two percent per annum to one and one half percent per annum based on historical price inflation. The inflation rate is based on current expectations and experience. The change in estimate was made on a prospective basis and, in conjunction with the June 30, 2010 adjustment to the discount rate from four percent to three and one half percent, resulted in a net adjustment to the ARO liability of $21 million as at December 31, 2010. Pengrowth has estimated the net present value of its total ARO to be $447 million as at December 31, 2010 (January 1, 2010 $451 million), based on a total escalated future liability of $1.8 billion (January 1, 2010 $2.2 billion). These costs are expected to be incurred over 50 years with the majority of the costs incurred between 2041 and 2076.

Table of Contents

23. RECONCILIATION FROM PREVIOUS GAAP TO IFRS (continued)

Use of the risk free discount rate of three and one-half percent and inflation rate of two percent resulted in an increase to the ARO assumed upon the acquisition of Monterey of $4 million, which is offset by an increase to goodwill.

The accretion of ARO decreased approximately $5 million for the year ended December 31, 2010 compared to previous GAAP, due to the use of the different discount rates.

The effect on the Balance Sheet as a result of changes to Provisions upon the implementation of IFRS can be quantified as follows:

	As at January 1, 2010	As at December 31, 2010
Increase to ARO due to:		
Initial change in discount rate	$ 359,884	$ 359,884
Initial change in timing and cost assumptions	(198,069)	(198,069)
ARO additions		6,025
ARO accretion		(5,216)
ARO revisions		20,676
ARO assumed in business combinations		4,230
	$ 161,815	$ 187,530
Amounts not affecting deficit		
ARO additions	$	$ (6,025)
ARO revisions		(20,676)
ARO assumed in business combinations		(4,230)
	161,815	156,599
Tax Effect	(63,108)	(38,259)
Increase to deficit	$ 98,707	$ 118,340

The effect on the Statement of Income as a result of changes to Provisions upon the implementation of IFRS can be quantified as follows:

	Year ended December 31, 2010
Increase to net income due to accretion	$ 5,216
Tax Effect	(1,399)
Increase to net income due to accretion	$ 3,817

(c) Goodwill

Under IFRS, the asset retirement obligation assumed upon acquisition of Monterey Exploration in the third quarter of 2010 is valued using the above noted IFRS discount and inflation rate. All other assets and liabilities assumed, as well as consideration paid, in this business combination is unchanged under IFRS as compared to previous GAAP. As a result, the increase in the asset retirement obligation assumed results in a corresponding increase in goodwill of $4 million at December 31, 2010.

(d) Other assets

Pengrowth re-designated the Judy Creek Remediation Trust Fund and the Private Company Investment as fair-value-through-profit-or-loss upon transition to IFRS and recorded these assets at fair value. Changes in the fair value are recognized in income. The effect of the transition to IFRS was a $7 million increase to other assets at January 1, 2010 (December 31, 2010 $7 million) with a corresponding increase to opening retained earnings upon transition to IFRS.

Table of Contents

23. RECONCILIATION FROM PREVIOUS GAAP TO IFRS (continued)

The effect on Other Assets of the implementation of IFRS can be quantified as follows:

	As at January 1, 2010	As at December 31, 2010
Increase in other assets due to:		
Increase in private company investment	$ 7,000	$ 7,000
Increase (decrease) in remediation funds	(16)	1
	$ 6,984	$ 7,001
Tax Effect	(891)	(887)
Decrease to deficit	$ 6,093	$ 6,114

(e) Deferred income taxes

Under IFRS, deferred income taxes are reported as a non-current liability resulting in a reclassification of the $1 million deferred tax asset to be netted against long term deferred tax liabilities at January 1, 2010 and a reclassification of $1 million of current deferred tax liability to long term deferred tax liability as of December 31, 2010.

Under IFRS, taxable temporary differences in the legal entity financial statements of Pengrowth Energy Trust must be measured using the top marginal personal tax rate of 39%, as opposed to the effective corporate tax rate used under previous GAAP of 25% at January 1, 2010 and December 31, 2010. As Pengrowth Energy Trust had significant unutilized tax pools prior to conversion to a dividend paying corporation, this resulted in the recognition of a deferred tax asset of approximately $164 million at January 1, 2010 (December 31, 2010 $164 million). Approximately $158 million of the deferred tax asset recognized on transition was recorded as a decrease to the opening deficit as of January 1, 2010. Approximately $6 million of the deferred tax asset resulted in an increase to trust unit holders capital at January 1, 2010 related to equity issue costs (December 31, 2010 $6 million). Upon conversion to a dividend paying corporation on December 31, 2010, the deferred tax asset was adjusted to the corporate tax rate of approximately 25% and eliminated through earnings, resulting in a deferred tax expense at December 31, 2010 of $158 million and a decrease to shareholders capital of $6 million.

The effect on the Balance Sheet of changes in deferred income taxes can be quantified as follows:

	As at January 1, 2010	As at December 31, 2010
Increase in tax liability due to increase in property, plant and equipment	$ (4,403)	$ (38,313)
Decrease in tax liability due to increase in provisions	63,108	38,259
Increase in tax liability due to increase in other assets	(891)	(887)
Decrease in tax liability due to changes to carrying value of net assets	$ 57,814	$ (941)
Decrease in tax liability due to changes in effective tax rate	163,774	
Decrease (increase) in deferred tax liability	$ 221,588	$ (941)

	As at January 1, 2010	As at December 31, 2010
Previous GAAP tax liability	$ (180,671)	$ (237,753)
Decrease (increase) in deferred tax liability	221,588	(941)
IFRS deferred tax asset (liability)	$ 40,917	$ (238,694)

Table of Contents

23. RECONCILIATION FROM PREVIOUS GAAP TO IFRS (continued)

The effect on the Statement of Income of changes in deferred income tax expense (reduction) can be quantified as follows:

	Year ended December 31, 2010
Increase to deferred income tax expense due to:	
Increase in tax expense due to increase in property, plant and equipment	33,910
Increase in tax expense due to decrease in ARO accretion expense	1,399
Increase in tax expense due to increase in other assets	4
Increase in tax expense due to change in ARO liability	23,442
Reversal of decrease in tax liability due to changes in effective tax rate	157,395
Increase in tax expense	$ 216,150

(f) Shareholder s capital

Under IFRS, the tax benefits of trust unit issue costs are measured at the top marginal rate, as per Note 23 (e). This results in an increase to the Trust Unitholders Capital of $6 million on transition to IFRS on January 1, 2010 (December 31, 2010 $6 million). This amount is reversed upon conversion to a dividend paying corporation on December 31, 2010.

Under IFRS, the redemption of the exchangeable shares issued in the Monterey business combination was measured at the fair value of the trust units or common shares on the date of issue. Under previous GAAP, the redemption of the exchangeable shares was measured at the carrying value of the shares. As a result of this difference, the value of shareholders capital increased by $9 million at December 31, 2010 (January 1, 2010 NIL) with a corresponding decrease to contributed surplus.

Under IFRS, changes to the January 1, 2010 opening balance sheet, other than reclassifications, are offset against the opening deficit. In addition, as a result of the transition to IFRS, net income in 2010 differs from the amounts reported under previous GAAP.

Pursuant to a Plan of Arrangement, shareholders capital was reduced by the amount of the consolidated deficit upon conversion to a dividend paying corporation on December 31, 2010. As the deficit was measured differently under IFRS compared to previous GAAP, the amount of the deficit eliminated and the corresponding reduction to shareholders capital differed under IFRS.

The effect on the deficit of the implementation of IFRS can be quantified as follows:

	As at January 1, 2010	As at December 31, 2010
Increase due to provisions	$ (98,707)	$ (118,340)
Decrease due to change in property, plant and equipment	11,009	107,595
Decrease due to change in other assets	6,093	6,114
Decrease due to change in tax liability for change in tax rate applied to the Trust	157,395	
Decrease (increase) in deficit	$ 75,790	$ (4,631)
Previous GAAP deficit	(2,144,521)	
Elimination of deficit		4,631
IFRS deficit	$ (2,068,731)	$
Previous GAAP shareholders capital	$ 4,920,945	$ 3,167,383
Increase to shareholders capital due to change in effective tax rate	6,379	
Increase to shareholders capital due to redemption of exchangeable shares		8,967
Elimination of deficit		(4,631)
IFRS shareholders capital	$ 4,927,324	$ 3,171,719

Table of Contents

23. RECONCILIATION FROM PREVIOUS GAAP TO IFRS (continued)

(g) Reclassifications

Under previous GAAP, interest and financing charges, realized foreign exchange loss (gain), unrealized foreign exchange loss (gain), accretion and the gain on equity investment were disclosed as separate line items in the statement of income. Under IFRS, these amounts were unchanged, but reported below the determination of operating income. Under previous GAAP, amortization of injectants for miscible floods were disclosed separately; under IFRS amortization of miscible floods is included with depletion, depreciation and amortization. Under previous GAAP, certain transportation costs were recorded as a reduction of oil and gas sales; under IFRS these costs are unchanged, but reported as transportation costs.

Interest paid is disclosed as a financing item in the statement of cash flows resulting in an increase in cash flow provided by operating activities and a corresponding increase in cash used for financing activities of $72 million for the year ended December 31, 2010.

Purchases of injectants are classified as a use of cash for investing under IFRS as the costs are capitalized to PP&E, resulting in a $9 million increase in the cash provided by operating activities and a corresponding increase in the cash used in investing activities for the year ended December 31, 2010.

The statement of cash flows includes a subtotal for funds flow from operations which is determined as cash flow from operations after interest and financing charges but before changes in working capital and expenditures on remediation.

Table of Contents

APPENDIX D

SUPPLEMENTAL UNAUDITED DISCLOSURES

ABOUT OIL AND GAS PRODUCING ACTIVITIES REQUIRED UNDER UNITED STATES GENERALLY ACCEPTED

ACCOUNTING PRINCIPLES

Table of Contents

SUPPLEMENTAL INFORMATION   OIL AND GAS PRODUCING ACTIVITIES

(unaudited)

The following are supplementary oil and gas disclosures required as a result of Pengrowth being an SEC registrant. All amounts pertain to Pengrowth s audited annual financial statements prepared in accordance with International Financial Reporting Standards (IFRS). Amounts for the year ended December 31, 2010 have also been restated to conform to IFRS. All amounts are in thousands of Canadian dollars unless otherwise noted.

OIL AND GAS RESERVES

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations.

Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Canadian provincial royalties are determined based on a graduated percentage scale which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume royalty rates in existence at the time the estimates were made, Pengrowth s estimated future production volumes and SEC Modernization of Oil and Gas Reporting rules, using the average of the first-day-of-the-month prices for the prior 12 month period. This same 12 month average price is also used in calculating the aggregate amount of (and changes in) future cash inflows related to the standardized measure of discounted future net cash flows. The unaudited supplemental information on oil and gas exploration and production activities for 2011 and 2010 has been presented in accordance with the SEC Modernization of Oil and Gas Reporting reserve estimation and disclosure rules. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause the Corporation s share of future production from Canadian reserves to be materially different from that presented.

Table of Contents

Subsequent to December 31, 2011 no major discovery or other favorable or adverse event is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

Costs incurred in oil and gas producing activities for the years ended December 31 are as follows:

	2011	2010
Property acquisition costs		
Proved	$ 3,139	$ 125,946
Unproved	5,489	464,593
Exploration costs	88,183	34,058
Development costs	735,335	282,931
Injectants costs	4,126	9,324
	$ 836,272	$ 916,852

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire oil and gas properties.

Development and exploration costs include the costs for drilling and equipping development and exploratory wells, constructing facilities to extract, treat, gather and store oil and gas. Development costs also include capitalized costs associated with additions to asset retirement obligations.

Injectants (mostly ethane and methane) are used in miscible flood programs to stimulate incremental oil recovery. The cost of injectants purchased from third parties for miscible flood projects is deferred and amortized over the period of expected future economic benefit which is estimated to be 24 months.

Pengrowth capitalizes a portion of general and administrative costs associated with exploration and development activities.

Approximately $564 million (2010 $512 million) of capitalized costs to acquire and evaluate unproven and development properties has been excluded from depletion.

Table of Contents

CAPITALIZED COSTS RELATING TO OIL AND GAS PRODUCING ACTIVITIES

The capitalized costs and related accumulated depreciation, depletion and amortization, including impairments, relating to Pengrowth s oil and gas exploration, development and producing activities at December 31 consist of:

	2011	2010
Oil and natural gas assets	4,053,977	3,714,841
Add: Exploration and evaluation assets	563,751	511,569
	4,617,728	4,226,410
Unproved oil & gas properties		
Unproven properties included in oil and natural gas assets	807,651	772,000
Exploration and evaluation assets	563,751	511,569
	1,371,402	1,283,569
Proven oil & gas properties	3,246,326	2,942,841
Total capitalized costs	4,617,728	4,226,410

Table of Contents

OIL AND GAS RESERVE INFORMATION

All of Pengrowth s proved oil, natural gas liquids, and natural gas reserves are located in Canada, in the provinces of Alberta, British Columbia, Saskatchewan and Nova Scotia. Pengrowth s proved developed and undeveloped reserves after deductions of royalties are summarized below:

Net Proved Developed and Undeveloped Reserves After Royalties

	Crude Oil and NGL's MMbbl	Natural Gas Bcf
End of year 2009	**97.5**	**415.4**
Revisions of previous estimates (including infill drilling & improved recovery)	5.2	87.3
Purchase of reserves in place	0.6	52.2
Sale of reserves in place	(0.1)	(1.2)
Discoveries and extensions	3.2	19.5
Production	(10.6)	(68.6)
End of year 2010	**95.8**	**504.6**
Revisions of previous estimates (including infill drilling & improved recovery)	10.6	26.3
Purchase of reserves in place		0.1
Sale of reserves in place	(0.2)	(0.4)
Discoveries and extensions	10.1	41.0
Production	(10.7)	(70.2)
End of year 2011	**105.6**	**501.4**

Net Proved Developed Reserves After Royalty

	Crude Oil and NGL's MMbbl	Natural Gas Bcf
End of year 2008	87.9	474.4
End of year 2009	81.7	394.0
End of year 2010	81.3	439.4
End of year 2011	85.9	436.1

Notes:

1. Net after royalty reserves are Pengrowth s lessor royalty, overriding royalty, and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Crown royalties are subject to change by legislation or regulation and vary depending on production rates, selling prices and potentially timing of initial production.

2. Reserves are the estimated quantities of crude oil, natural gas and related substances anticipated from geological and engineering data to be recoverable from known accumulations, from a given date forward, by known technology, under existing operating conditions and the average of the commodity prices on the first day of each month for the year ended December 31, 2011 and 2010.

3. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

4. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped reserves are reserves that are expected to be recovered from known accumulations where a significant expenditure is required.

Table of Contents

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

The following information is based on crude oil and natural gas reserve and production volumes estimated by the independent engineering consultants of Pengrowth. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating Pengrowth or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Pengrowth s reserves.

The future cash flows presented below are based on cost rates, and statutory income tax rates in existence as of the date of the projections and the average of commodity prices in effect on the first day of each month for the year ended December 31, 2011 and December 31, 2010. It is expected that revisions to some estimates of crude oil and natural gas reserves may occur in the future, due to development and production of the reserves that may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2011 was based on the following average of the first-day-of-the-month benchmark prices for the twelve month period before the end of the year: Edmonton par crude oil price of $97.03/bbl (2010 $78.23/bbl) and AECO natural gas price of $3.78/MMBtu (2010 $4.06/MMBtu).

STANDARDIZED MEASURE OF DISCOUNTED FUTURE CASH FLOW RELATING TO PROVED OIL AND GAS RESERVES

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Pengrowth s crude oil and natural gas reserves at December 31, for the years presented.

	2011	2010
Future cash inflows	$ 13,677	$ 10,761
Future costs		
Future production and development costs	(7,826)	(6,302)
Future income taxes	(655)	(261)
Future net cash flows	5,196	4,198
Deduct: 10% annual discount factor	(2,152)	(1,649)
Standardized measure of discounted future net cash flows	$ 3,044	$ 2,549

Table of Contents

CHANGES IN STANDARDIZED MEASURE OF DISCOUNTED FUTURE CASH FLOW RELATING TO PROVED OIL AND GAS RESERVES

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, for the years presented.

	2011 $MM	2010 $MM
Future discounted net cash flow at beginning of year	2,549	1,735
Sales & transfer, net of production costs	(759)	(719)
Net change in sales & transfer prices	599	706
Development costs incurred during the period	581	324
Change in future development costs	(752)	(448)
Change due to extensions, discoveries and improved recovery	297	94
Change due to revisions (including infill drilling)	363	198
Accretion of discount	262	203
Sales of reserves in place	(4)	(3)
Purchase of reserves in place	1	136
Net change in Income Taxes	(212)	228
Changes in timing of future net cash flow and other	119	95
Future discounted net cash flow at end of year	3,044	2,549

Note:

1. The schedules above are calculated using year-end costs, statutory tax rates and proved oil and gas reserves and the average of the commodity prices on the first day of each month for the years ended December 31, 2011 and 2010. The value of exploration properties and probable reserves, future exploration costs, future changes in oil and gas prices and in production and development costs are excluded.

Table of Contents

APPENDIX E

PENGROWTH ENERGY CORPORATION CODE OF BUSINESS CONDUCT AND ETHICS DATED NOVEMBER 4, 2011

Table of Contents

Pengrowth Energy Corporation

CODE OF BUSINESS CONDUCT

AND ETHICS

Approved by the Board of Directors on November 4, 2011

TABLE OF CONTENTS

CODE OF BUSINESS CONDUCT AND ETHICS

APPLICATION

Unless expressly provided herein to the contrary, this Code of Business Conduct and Ethics (the **Code**) applies to all directors, officers, employees, consultants and contractors (each a **Member**) of Pengrowth Energy Corporation and its respective subsidiaries and affiliates (collectively, referred to herein as **Pengrowth**).

PURPOSE

This Code summarizes appropriate behaviour for maintaining Pengrowth s reputation for honesty and integrity earned by maintaining the highest standards of business ethics and compliance with applicable laws, rules and regulations in all our interactions with our fellow Members, governments, local communities, securityholders, customers, suppliers, competitors and the public.

POLI CY

Pengrowth and all of its Members will adhere to the highest ethical standards and compliance with laws, rules and regulations in all our business activities. Any situation, decision or response should first consider what is right and how it reflects on Pengrowth. Although the various matters described in this Code do not cover the full spectrum of employee and contractor activities, they are indicative of the type of behaviour expected from employees and contractors in all circumstances.

COMPLIANCE WITH CODE

Members are expected to comply with all aspects of this Code. This Code does not specifically address every potential form of unacceptable conduct, and it is expected that Members will exercise good judgment in compliance with the principles set out in this Code. Each Member has a duty to avoid any circumstance that would violate the letter or spirit of this Code.

COMPLIANCE WITH THE LAW

Each Member must ensure that his or her dealings and actions on behalf of Pengrowth comply with the spirit and intent of all relevant legislation, rules and regulations including those set by a self regulatory body or professional organization of all the countries in which Pengrowth operates or where Pengrowth s securities are listed on the exchanges.

ANTI-CORRUPTION POLICY

Pengrowth is subject to legislation in Canada, the United States and other jurisdictions that prohibit corrupt practices in dealing with foreign governments. All interaction and communications between Members and public officials are to be conducted in the highest ethical manner and must not compromise the integrity or reputation of any public official, Pengrowth, its affiliates or its employees. Members are expected to read, understand and adhere to Pengrowth s **Anti-Corruption Policy**.

Table of Contents

Health, Safety and the Environment

Pengrowth is committed to safe and healthful working conditions for all Members and third parties, and to conducting its activities in an environmentally responsible manner consistent with the principles of sustainable development.

Members are expected to read, understand and adhere to Pengrowth s Environmental, Health and Safety Policies and Procedures and participate fully in this effort by improving operations to avoid injury or sickness to persons, and damage to property and the environment and by giving due regard to all applicable safety standards, regulatory requirements, technical and conventional standards and restraints.

Maintaining Records

Accurate, timely and reliable books of account and records are essential for effective management to ensure Pengrowth meets its business, legal and financial obligations. Members are to safeguard Pengrowth s records and adhere to retention guidelines.

Accounting and Financial Reporting

Pengrowth is committed to achieving compliance with all applicable securities laws and regulations, accounting standards, accounting controls and audit practices. Every Member is required to follow prescribed accounting and financial reporting procedures. All accounting records should accurately reflect and describe corporate transactions and that all transactions are fairly, completely, accurately, timely and understandably accounted for and recorded in accordance with Pengrowth s policies and procedures. The recording of such data must not be falsified or altered in any way to conceal or distort assets, liabilities, revenues, expenses or the nature of the activity.

Any suspected violation relating to accounting or financial reporting matters should be reported pursuant to procedures described in Appendix A Complaint Procedures for Accounting, Financial Reporting and Auditing Matters and Violations of the Code of Business Conduct and Ethics to this document.

It is essential that all Members follow established policies, procedures and internal controls. Any exception to established policies, procedures and internal controls (excluding to this Code) is prohibited, unless appropriately authorized in advance by any officer of Pengrowth who shall report all such approved exceptions to the Audit and Risk Committee. Exceptions to this Code are dealt with below under Exceptions .

Assistance to Auditors

No information should be concealed from the internal or external, independent auditors.

Public Reporting

Persons responsible for the preparation of documents and reports and other public communications that Pengrowth files with, or submits to, the securities commissions and in its other public communications to comply with its obligations under the securities laws and to meet the expectations of its securityholders and other members of the investment community, are to exercise the highest standard of care in their preparation in accordance with the applicable laws and must include full fair, accurate, timely and understandable disclosure.

Enquiries from members of the community related to matters of a sensitive nature should be directed to a member of senior management. Any member of senior management receiving such an enquiry is then required to refer the matter to either the President and Chief Executive Officer (the **CEO**), Chief Financial Officer or General Counsel whereby such senior officers will respond on behalf of Pengrowth.

All Members responsible for disclosure are expected to read, understand, adhere to and must act according to Pengrowth s **Corporate Disclosure Policy**.

Table of Contents

Conflict of Interest

Members must avoid interests or relationships where their personal interests may affect, or appear to affect, their judgment in acting in the best interests of Pengrowth. This requires that each Member act in such a manner that his or her conduct will bear the closest scrutiny should circumstances demand that it be examined. Where a conflict of interest situation may exist, or be perceived to exist, the Member may be put in a compromising position or his or her judgement may be questioned. Pengrowth wants to ensure that all Members are, and are perceived to be, free to act in the best interests of Pengrowth.

There are many situations which can be classified as conflicts of interest, but the following examples illustrate those that are most common.

Private Business Interest

Unless otherwise consented to by the General Counsel, a Member, either directly or indirectly through his or her immediate family or by any other means, must not have a personal financial interest in, or place himself or herself in a position where he or she could derive a benefit or interest from, a business transaction with Pengrowth, which financial interest or benefit is of such a nature that it would reasonably be expected to create a conflict of interest for the Member.

This, however, does not prevent a Member and his or her family from having ownership in publicly traded shares or equity in companies which may do business with Pengrowth. Nor does it prevent a consultant or contractor from providing his or her services to Pengrowth through a third party corporation.

Involvement with Not-for-Profit Organizations

As a responsible community citizen, Pengrowth encourages and supports Member participation in charitable, educational, cultural, political and not-for-profit organizations. Members are reminded that such participation should not be of a nature or extent that it adversely affects a Member s job performance or puts the Member in a conflict of interest position.

Outside Employment

Pengrowth recognizes that some employees may, from time to time, hold additional part-time employment outside their employment relationship with Pengrowth. Employees are reminded that any such outside employment should not be of a nature or extent that it adversely affects the employee s job performance at Pengrowth or put the employee in a conflict of interest position. All employees who hold management positions with Pengrowth shall obtain the approval of the General Counsel before accepting any such outside employment.

Directorships

Any officer or employee shall obtain the approval of the CEO prior to accepting a position as a director of a for-profit company or any business organization. The CEO shall obtain the approval of the Board of Directors prior to accepting a position as a director of a for-profit company or any business organization. A director shall advise the Chairman of the Board prior to accepting a position as a director of a for-profit company or any business organization.

Related Party Transaction

In addition to the consent requirement set out under Private Business Interest above, each director and officer who is a party to a material contract or proposed material contract with Pengrowth or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with Pengrowth of which he has knowledge is required to disclose in writing to the Chairman of the Board the nature and extent of the director s or officer s interest. The Chairman of the Board shall make any such disclosure concerning himself to the Chair of the Corporate Governance and Nominating Committee.

Table of Contents

Corporate Property and Opportunities

Members are prohibited from taking for themselves, opportunities that arise through the use of corporate property, information or position and from using corporate property, information or position for personal gain.

DISCLOSURE OF CONFLICT OF INTEREST

Disclosure of areas of potential conflict of interest will allow appropriate steps to be taken to protect the individual from these situations.

Officers, employees, consultants and contractors are required to disclose to the appropriate Vice President in writing all business, commercial or financial interests and activities which might reasonably be regarded as creating an actual or potential conflict with their duties of employment. Senior management will determine whether a conflict of interest does or could exist and, if necessary, advise the person as to what steps should be taken. Directors are required to disclose to the Chair of the Corporate Governance and Nominating Committee (or, in the case of the Chair of the Corporate Governance and Nominating Committee, to the other members of the Committee) all business, commercial or financial interests and activities which might reasonably be regarded as creating an actual or potential conflict with their duties as directors.

GIFTS AND ENTE RTAINMENT

The exchange of gifts and entertainment is a common practice in most business communities and is designed to develop and foster goodwill among business partners. Accepting gifts and entertainment can cause problems when they compromise, or appear to compromise, our ability to make fair and objective business decisions. No gift or entertainment should be accepted, or offered, if it will unfairly influence a business relationship.

There are many factors that influence whether a gift or entertainment is normal and customary. Gifts or entertainment should be moderate, reasonable and in good taste, be of a style or value commonly accepted for business occasions and should not be unusual for the recipient s job or community. The exchange must create no obligation or sense of obligation and should occur infrequently.

Business entertainment can present situations where discretion is required since some commonly accepted business invitations can include recreational opportunities or event tickets that are of significant value. In these cases, the recipient should ensure that there is a valid business development reason for attending. If the invitation is for an event where the value being received may be significant, prior approval by an officer of Pengrowth is required, or in the case of the CEO, approval by the Chair of the Corporate Governance and Nominating Committee. As transportation costs for events can also be significant, payment of these costs by another party is not acceptable and will be covered by Pengrowth if there is a valid business reason to accept the invitation.

FAIR DEALINGS

It is Pengrowth s policy to deal fairly and lawfully with all securityholders, customers, suppliers, competitors and Members. All goods and services shall be obtained on a competitive basis at the best value considering price, quality, reliability, availability and delivery.

POLITICAL ACTIVITIES AND CONTRIBUTIONS

Pengrowth respects and supports the right of its employees to participate in political activities. However, these activities should not be conducted on Pengrowth time or involve the use of any Pengrowth resources. Employees will not be reimbursed for personal political contributions.

Pengrowth may occasionally express its views on local and national issues that affect its operations. In such cases, Pengrowth funds and resources may be used, but only when permitted by law and by Pengrowth s strict guidelines. On very limited occasions, Pengrowth may also make limited contributions to political parties or candidates in jurisdictions where it is legal and customary to do so. Pengrowth may pay related administrative and solicitation costs for political action committees formed in accordance with the political laws and regulations. No employee may make or commit to political contributions on behalf of Pengrowth without the approval of the Chief Executive Officer.

Confidential Information

In the course of their work, Members may have access to information that is confidential, privileged, of value to competitors of Pengrowth or might be damaging to Pengrowth if improperly disclosed. Pengrowth respects privileged business and employee related information, and therefore all Members must protect the confidentiality of such information.

Use of Confidential Information

The use or disclosure of confidential information must be for Pengrowth s purposes only and not for personal benefit or the benefit of others. This applies to disclosure of confidential information concerning Pengrowth or its business activities as well as information with respect to companies having business dealings with Pengrowth. To preserve confidentiality, disclosure and discussion of confidential information should be limited to those individuals who need to know the information. Members are expected to read, understand and adhere to Pengrowth s **Corporate Disclosure Policy** and Confidentiality Agreements.

Disclosure of Confidential Information

Members must guard against improper disclosure of information that may be of competitive value to Pengrowth. Pengrowth is in a competitive environment with other companies. Certain records, reports, papers, devices, processes, plans, methods and apparatus of Pengrowth, including methods of doing business, strategies and information on costs, prices, sales, profits, markets and opportunities are the property of Pengrowth and are considered to be confidential and proprietary. Members must not reveal such confidential information without consent of the General Counsel.

Confidential information does not include information which is already in the public domain. Certain information may be released by Pengrowth (to comply with securities regulations, for example) however, the release of such information is a decision of the Board of Directors and senior management. If there is any doubt as to what can or cannot be discussed outside of Pengrowth, Members should err on the side of discretion and not communicate any information. For more specific advice, your immediate manager, the CEO, the Chief Financial Officer or General Counsel should be consulted.

These obligations regarding confidential information continue to apply to all Members following cessation of their employment or contractual relations with Pengrowth. Members are expected to read, understand and adhere to Pengrowth s **Corporate Disclosure Policy** and Confidentiality Agreements.

Inside Information

Certain information, which Pengrowth treats as confidential, may influence the price or trading of Pengrowth s common shares or other securities if it is disclosed to members of the public. Inside information would include information concerning exploration well results, major contracts, proposed acquisitions or mergers, and earnings figures. Members shall not use such inside information for their own financial gain or for that of their associates.

If in doubt as to the propriety of actions, the Member should seek the advice of the CEO, Chief Financial Officer or General Counsel. Members are expected to read, understand and adhere to Pengrowth s **Policy on Trading in Securities**.

Protection and Use of Assets

All Members are responsible for protecting Pengrowth s assets and their efficient use for legitimate business purposes only. Pengrowth provides Members with computer and Internet access for work purposes. Members are expected to read, understand, acknowledge and adhere to Pengrowth s **Acceptable Use Policy** for Information System Assets.

Table of Contents

Intellectual Property - Patents, Inventions, Discoveries and Copyrights

All intellectual property including inventions, discoveries and copyrights made by Members during or as a result of their employment or contractual relations with Pengrowth (where company time, equipment, resources or pertinent information has been used for personal gain) are the property of Pengrowth unless a written release is obtained from the CEO.

Pengrowth and its Members honour the proprietary rights of others as expressed in patents, copyrights, trademarks and industrial design.

Employee Relations and Reporting

Pengrowth values the diversity of its Members and is committed to providing equal opportunity in all aspect of employment. In working together, Members must ensure they treat each other with respect, dignity, honesty, fairness and provide a healthy environment that is free of harassment, offensive behaviour and discrimination.

All Members are encouraged to report any behaviour of other Members which they reasonably believe is illegal or unethical and any suspected violation relating conduct matters should be reported pursuant to procedures described in Appendix A Complaint Procedures for Accounting, Financial Reporting and Auditing Matters and Violations of the Code of Business Conduct and Ethics to this document or to the Vice President, Human Resources or the General Counsel.

Compliance with Policies, Procedures and Internal Controls and Exception Reporting

Members should ensure all transactions with which they are involved are authorized and executed in accordance with Pengrowth s policies and procedures and conform to all legal and accounting requirements Members are expected to read, understand and adhere to Pengrowth s Delegation of Authorities guideline.

Whenever a Member is in doubt about the application or interpretation of any legal requirement or has questions about whether particular circumstances may involve illegal conduct, the individual should immediately seek the advice of his or her manager or consult Pengrowth s General Counsel.

Reporting Violation or Suspected Violation of this Code or Law

It is important that Pengrowth be made aware of circumstances that may indicate possible violations of law or this Code. Any violations of this Code must be promptly reported pursuant to procedures described in Appendix A Complaint Procedures for Accounting, Financial Reporting and Auditing Matters and Violations of the Code of Business Conduct and Ethics to this document.

No Retaliation for Raising Concern

Any Member may submit a complaint regarding a suspected violation of the Code without fear of dismissal or retaliation. Pengrowth and applicable law prohibit any form of retaliation for raising concerns or reporting possible misconduct in good faith or for assisting in the investigation of possible misconduct. No adverse action will be taken against any individual for making a complaint or disclosing information in good faith. Any Member who retaliates in any way against an individual who, in good faith, reports any violation, or suspected violation, of this Code, will be subject to disciplinary action.

Consequence of Non-Compliance with Code or Law

Non-compliance with this Code or the law or other dishonest or unethical business practices are forbidden and may result in disciplinary action, including termination from employment or termination of contractual relations.

Pengrowth is required to cooperate with investigations by regulatory authoritative bodies and quasi-judicial tribunals to the extent that a policy violation breaks a law or regulation.

Questions Regarding this Code or Law

If a Member has any question of appropriateness in a particular situation, areas of conflict or disagreement with any aspect of this Code or any applicable laws, the matter should be discussed with the CEO, Chief Financial Officer, General Counsel or Chairman of the Board of Pengrowth.

This Code is not intended to address all of the situations you may encounter. There will be occasions where Members are confronted by circumstances not covered by this Code or procedure and where Members must make a judgment as to the appropriate course of action. In those circumstances, Members are encouraged to use common sense and to contact their respective supervisor, manager or other appropriate person for guidance.

Acknowledgement

It is essential that all Members understand and adhere to this Code.

All Members will be asked to acknowledge, in writing, their review of and agreement to be bound by this Code as a condition of their new or continuing employment or contractual relations, as the case may be. This acknowledgment must be made: (i) in the case of directors, upon election to the Board of Directors of Pengrowth and annually thereafter; (ii) in the case of officers and employees, upon the commencement of employment and annually thereafter, (iii) in the case of consultants and contractors, upon commencement of this contractual relation and annually thereafter, and such acknowledgement may be provided in electronic format.

The form of certification attached as Appendix B is to be used by each Member to disclose any ***personal*** facts or dealings that are non-compliant with this Code.

Exceptions

No provision of this Code will be waived in respect of a director or executive officer unless expressly approved by the Board of Directors. Any waiver of this Code in respect of a director or officer shall be disclosed to Pengrowth s shareholders by posting such waiver to Pengrowth s website promptly after Board approval and as otherwise required by law, regulation or stock exchange requirement. For greater certainty, the exercise of discretion by an executive officer or the Board of Directors, in compliance with this Code, shall not be considered a waiver of this Code.

Adopted by the Board of Directors of Pengrowth on November 4, 2011.

Table of Contents

APPENDIX A

COMPLAINT PROCEDURES FOR ACCOUNTING, FINANCIAL REPORTING AND AUDITING MATTERS AND VIOLATIONS OF THE CODE OF BUSINESS CONDUCT AND ETHICS

In order to facilitate the reporting of complaints, the Board of Directors of Pengrowth has established the following procedures for (i) the receipt, retention and treatment of complaints regarding accounting, internal accounting controls, financial reporting or auditing matters (**Accounting Matters**); (ii) the receipt, retention and treatment of complaints regarding suspected violations of the Code of Business Conduct and Ethics and any other conduct concerns (**Conduct Matters**); and (iii) the confidential, anonymous submission by directors, officers and employees of Pengrowth (collectively, **Members**) of concerns regarding questionable Accounting Matters and Conduct Matters.

RECEIPT OF COMPLAINTS

1. Through Management

Any Member may submit a complaint regarding Accounting Matters or Conduct Matters to the management of Pengrowth without fear of dismissal or retaliation of any kind.

2. Through Appropriate Committee Chair

Any Member with concerns regarding an Accounting Matter may report their concerns to the Chair of the Audit and Risk Committee. Pengrowth is committed to achieving compliance with all applicable securities laws and regulations, accounting standards, accounting controls and audit practices. The Audit and Risk Committee of Pengrowth will oversee and be responsible for the investigation of the treatment of Member concerns relating to Accounting Matters.

Any Member with concerns regarding a Conduct Matter may report their concerns to the Chair of the Corporate Governance and Nominating Committee. The Corporate Governance and Nominating Committee of Pengrowth will oversee treatment of Member concerns in Conduct Matters.

All such concerns will be set forth in writing and forwarded in a sealed envelope to the General Counsel of Pengrowth or, if the submitter so desires, directly to the Chair of the Audit and Risk Committee or Corporate Governance and Nominating Committee, in care of the General Counsel in an envelope labelled with a legend such as: To be opened by the Audit and Risk Committee only or To be opened by the Corporate Governance and Nominating Committee only.

If a Member would like to discuss any matter with the Audit and Risk Committee, the Member should indicate this in the submission and include a telephone number at which he or she can be reached, should the Audit and Risk Committee deem such communication is appropriate. Any such envelopes received by the General Counsel that are directed to the Audit and Risk Committee will be forwarded promptly and unopened to the Chair of the Audit and Risk Committee.

3. Through Anonymous Confidential Submission

Any Member may report concerns regarding an Accounting Matter or a Conduct Matter on a confidential or anonymous basis to Grant Thornton LLP, at 1-888-747-7171 or usecare@GrantThornton.ca.

Any Member who makes an anonymous submission must be sure to provide sufficient detail to identify the concern being raised. Given that the submission is made anonymously, the Audit and Risk Committee or the Corporate Governance and Nominating Committee, as the case may be, will be unable to follow up if there are additional questions. The submission should, at a minimum, contain dates, places, persons involved and witnesses or other information sufficient for recipient to investigate and determine whether the submission is valid or made in good faith such that a reasonable investigation or assessment can be conducted.

SCOPE OF ACCOUNTING MATTERS COVERED BY THESE PROCEDURES

These procedures relate to Members complaints relating to any questionable Accounting Matters, including, without limitation, the following:

Table of Contents

- fraud or deliberate error in the preparation, evaluation, review or audit of any financial statement of Pengrowth;
- fraud or deliberate error in the recording and maintaining of financial records of Pengrowth;
- deficiencies in or non-compliance with Pengrowth s internal accounting controls;
- misrepresentation or false statement to or by a director, officer, employee or external accountant regarding a matter contained in the financial records, financial reports or audit reports of Pengrowth; or
- deviation from full and fair reporting of Pengrowth s financial condition.

Treatment of Complaints

Grant Thornton LLP and Pengrowth shall inform (i) the Chair of the Audit and Risk Committee of all complaints and concerns provided to it in respect of Accounting Matters; and (ii) the Chair of the Corporate Governance and Nominating Committee of all complaints provided to it in respect of Conduct Matters.

Upon receipt of a complaint or concern, the Chair of the Audit and Risk Committee or Chair of the Corporate Governance and Nominating Committee, as the case may be, will (i) determine whether or not the complaint actually pertains to an Accounting Matter or a Conduct Matter and (ii) when possible, acknowledge receipt of the complaint to the sender.

Complaints relating to an Accounting Matter will be reviewed by the Audit and Risk Committee, outside legal counsel or such other person(s) as the Audit and Risk Committee determines to be appropriate. Complaints relating to a Conduct Matter will be reviewed by the Corporate Governance and Nominating Committee, outside legal counsel or such other person(s) as the Corporate Governance and Nominating Committee determines to be appropriate. In any case, confidentiality will be maintained to the fullest extent possible, consistent with the need to conduct an adequate review. If on preliminary examination the allegation is judged to be wholly without substance or merit, or not made in good faith, the allegation may be dismissed.

Prompt and appropriate investigation and corrective action will be taken when and as warranted in the judgment of the Audit and Risk Committee or the Corporate Governance and Nominating Committee, as the case may be.

If the identity of the Member making the complaint, or assisting in investigation of the complaint, is known by anyone within Pengrowth, the Audit and Risk Committee will monitor any disciplinary action against the Member to determine whether it could subject Pengrowth to anti-retaliation liability pursuant to Sections 806 or 1107 of the Sarbanes-Oxley Act. Pengrowth will not discharge, demote, suspend, threaten, harass or in any manner discriminate against any individual in the terms and conditions of employment based upon any lawful actions of such individual with respect to reporting of complaints in good faith regarding any Accounting Matter or any Conduct Matter or as otherwise specified in Section 806 of the Sarbanes-Oxley Act. In addition, Pengrowth will observe the anti-retaliation requirements of Section 1107 of the Sarbanes-Oxley Act, which establishes penalties for retaliation against any person who provides truthful information to a law enforcement officer regarding any offense.

Pengrowth will regard the making of any deliberately false or malicious allegations by an employee as a serious offence which may result in recommendations to the Board of Directors or to senior management of Pengrowth for disciplinary action including dismissal for cause and, if warranted, legal proceedings.

Reporting and Retention of Complaints and Investigations

The Chair of the Audit and Risk Committee and the Chair of the Corporate Governance and Nominating Committee will maintain a log of all complaints, tracking their receipt, investigation and resolution and shall prepare a periodic summary report thereof for the Audit and Risk Committee or the Corporate Governance and Nominating Committee, as the case may be.

Table of Contents

RECORD RETENTION

The chairs of the Audit and Risk Committee and the Corporate Governance and Nominating Committee, will work with the Corporate Secretary to ensure that, as part of each committee s respective records, any such complaints or concerns are retained in a manner which preserves their confidentiality, for a period of at least seven years.

Table of Contents

APPENDIX B

AWARENESS STATEMENT ON CODE OF BUSINESS CONDUCT AND ETHICS

To be completed by all directors, officers, employees, consultants and contractors of Pengrowth Energy Corporation and its subsidiaries (Pengrowth)

I have recently read the Code of Business Conduct and Ethics of Pengrowth (the **Code**), and I can certify that, except as specifically noted below:

1. I understand the content and consequences of contravening the Code and agree to abide by the Code.

2. I am in compliance with the Code.

3. All facts and dealings which I believe to be non-compliant with the Code have been communicated to the appropriate representative of Pengrowth and are detailed below.

4. (If applicable) After due inquiry and to my best knowledge and belief, no employee, consultant or contractor under my direct supervision is in violation of the Code.

5. I have and will continue to exercise my best efforts to assure full compliance with the Code by myself and (if applicable) all employees, consultants and contractors under my direct supervision.

Print or type name: _________________________

Signature: ________________________________

Title and location: __________________________

Date: ____________________________________

Facts and dealings that I believe to be non-compliant with the Code

(Including potential conflict of interest situations)

1.

2.

(If required, provide additional details on separate sheet).

Table of Contents

EXHIBIT INDEX

Exhibit	Description
99.1	Consent of Independent Registered Public Accounting Firm.
99.2	Consent of GLJ Petroleum Consultants Ltd.
99.3	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350
99.4	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350
99.5	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934
99.6	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934