

**PROGRESS ENERGY RESOURCES CORP.**

**Annual Information Form**

For the year ended December 31, 2009

March 8, 2010



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## SELECTED DEFINITIONS

In this Annual Information Form, the abbreviations and terms set forth below have the meanings indicated, unless otherwise indicated. **Additional terms relating to natural gas and petroleum reserves and operations have the meaning set forth under "Presentation of Progress' Natural Gas and Petroleum Reserves and Production Information"**.

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

"**Arrangement**" means the plan of arrangement involving the Company, the Trust and Progress Energy Ltd. completed on January 15, 2009 under the ABCA pursuant to which, among other things, the Company acquired all of the issued and outstanding Units of the Trust and Exchangeable Shares of Progress Energy Ltd. and the Company changed its name from "ProEx Energy Ltd." to "Progress Energy Resources Corp.";

"**Board of Directors**" or "**Board**" means the board of directors of Progress or its successors;

"**Business Day**" means a day, other than a Saturday or Sunday, or a statutory holiday, on which major Canadian chartered banks are open for business in Calgary, Alberta;

"**Cequel**" means Cequel Energy Inc., a corporation amalgamated under the ABCA;

"**Cyries**" means Cyries Energy Inc., a corporation incorporated under the ABCA;

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

"**CPPIB**" means the Canada Pension Plan Investment Board;

"**CRA**" means the Canada Revenue Agency;

"**CSA 51-324**" means the Staff Notice 51-324 - *Glossary To NI 51-101 Standards of Disclosure For Oil And Gas Activities* of the Canadian Securities Administrators;

"**Debenture Trustee**" means Computershare Trust Company of Canada;

"**Escrow Agent**" means Computershare Trust Company of Canada;

"**Exchangeable Shares**" means the exchangeable shares in the capital of Progress Energy Ltd.;

"**First Debentures**" means the 6.75% convertible unsecured subordinated debentures due June 30, 2010, which were assumed by the Company from the Trust on January 15, 2009 in connection with the Arrangement;

"**GAAP**" means generally accepted accounting principles;

"**GLJ**" means GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta;

"**GLJ Progress Report**" means the report prepared by GLJ dated February 8, 2010 evaluating the crude oil, natural gas, and natural gas liquids reserves attributable to certain of the Company's oil and natural gas assets at December 31, 2009;

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

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

**"Partnership"** means Progress Exploration Partnership 2009, a general Alberta partnership, the partners of which are the Corporation and Progress Energy Ltd.;

**"Private Placement Agreement"** means the subscription agreement between the Corporation and CPPIB dated February 9, 2010 pursuant to which CPPIB agreed, among other things, to purchase the Placement Subscription Receipts;

**"Private Subscription Receipt Agreement"** means the agreement dated March 2, 2010 between the Corporation, CPPIB and the Escrow Agent governing the terms of the Placement Subscription Receipts;

**"ProEx"** means ProEx Energy Ltd., an ABCA company which amalgamated with a wholly-owned subsidiary pursuant to the Arrangement to form the Company;

**"Progress", "we", "us", "our"** or the **"Company"** means Progress Energy Resources Corp., a corporation amalgamated under the ABCA and formerly named ProEx;

**"Progress Trust Indenture"** means the trust indenture dated as of May 26, 2004, among Progress Energy Ltd., Cequel and Computershare Trust Company of Canada, as amended and supplemented on January 15, 2009 pursuant to the Arrangement;

**"Public Subscription Receipt Agreement"** means the agreement dated March 2, 2010 between the Corporation, the Underwriters and the Escrow Agent governing the terms of the Offering Subscription Receipts;

**"Second Debentures"** means the 6.25% convertible unsecured subordinated debentures due September 30, 2011, which were assumed by the Company from the Trust on January 15, 2009 in connection with the Arrangement;

**"Shareholders"** or **"Shareholder"** means holders from time to time of the Shares;

**"Shares"** means the common shares of the Company;

**"Tax Act"** means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1 (5th Supp), as amended, including the regulations promulgated thereunder;

**"Third Debentures"** means the 5.25% convertible unsecured subordinated debentures due October 14, 2014 which were issued by the Company on October 23, 2009;

**"Trust"** means Progress Energy Trust, a trust formed pursuant to the laws of Alberta pursuant to the Progress Trust Indenture which was acquired by the Company on January 15, 2009 in connection with the Arrangement and subsequently wound up. All references to the "Trust", unless the context otherwise requires, are references to Progress Energy Trust, its predecessors and its subsidiaries;

**"TSX"** means the Toronto Stock Exchange;

**"Underwriters"** means, collectively, BMO Nesbitt Burns Inc., CIBC World Markets Inc., Peters & Co. Limited, RBC Dominion Securities Inc., Scotia Capital Inc., Cormark Securities Inc., FirstEnergy Capital Corp., National Bank Financial Inc., Canaccord Financial Ltd. and Macquarie Capital Markets Canada Ltd.;

**"United States"** or **"U.S."** means the United States of America;

**"Unitholders"** or **"Unitholder"** means holders from time to time of the Units; and

**"Units"** means the trust units of the Trust.

All dollar amounts set forth in this Annual Information Form are in Canadian dollars, except where otherwise indicated. Unless otherwise specified, information in this Annual Information Form is as at the end of the Company's most recently completed financial year, being December 31, 2009. Totals may not add due to rounding.

## ABBREVIATIONS AND CONVERSIONS

In this Annual Information Form, the following abbreviations have the meanings set forth below.

AECO	Alberta Energy Company interconnect with Nova system, the Canadian benchmark for natural gas pricing
API	American Petroleum Institute
bbl/d	Barrels per day
Bbls	Barrels
Bcf	Billion cubic feet
BOE	Barrel of oil equivalent of natural gas and crude oil on the basis of one bbl of crude oil for 6 Mcf of natural gas as is indicated in the context.
BOE/d	Barrel of oil equivalent per day
GJ	Gigajoule
m <sup>3</sup>	Cubic metres
Mbbl/d	Thousand bbls per day
Mbbl	Thousand barrels
Mcf	Thousand cubic feet
MBOE	Thousand barrels of oil equivalent
Mcfpd	Thousand cubic feet per day
MMbbl	Million barrels
MMBOE	Million barrels of oil equivalent
MMBtu	One million British thermal units
MMcf	Million cubic feet
MMcfpd	Million cubic feet per day
NGLs	Natural gas liquids
WTI	West Texas Intermediate of Cushing, Oklahoma, the benchmark for crude oil pricing purposes

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

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	bbls oil	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.50 (Alberta and British Columbia)
Gigajoules	MMbtu	0.950
MMbtu	Gigajoules	1.0526

**PRESENTATION OF PROGRESS' NATURAL GAS AND  
PETROLEUM RESERVES AND PRODUCTION INFORMATION**

**Disclosure of Information**

**The Company's actual natural gas and petroleum reserves and future production will be greater than or less than the estimates provided in this Annual Information Form. The estimated future net revenue from the production of the Company's natural gas and petroleum reserves does not represent the fair market value of the Company's reserves.**

The Company has adopted the standard of 6 mcf:1 BOE when converting natural gas to BOEs. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

**Note to Reader Regarding Natural Gas and Petroleum Information, Definitions and NI 51-101**

The natural gas and petroleum operational and reserves information for the Company contained in Appendix A-3, of this Annual Information Form contains the information required to be included in the Statement of Reserves Data and Other Oil and Gas Information pursuant to NI 51-101 adopted by the Canadian securities regulatory authorities and is presented in accordance with Form 51-101FI. Readers should also refer to the Report of Management and Directors on Oil and Gas Disclosure in Appendix A-1 and the Report on Reserves Data by GLJ attached hereto as Appendix A-2. The effective date for the Statement of Reserves Data and Other Oil and Gas Information contained in this Annual Information Form is December 31, 2009 and the information contained in the Annual Information Form has been prepared as of February 8, 2010.

Certain of the following definitions and guidelines have been prepared by the Standing Committee on Reserves Definitions of the CIM (Petroleum Society). Further information is contained in Section 5.4 of Volume 1 of the COGE Handbook (First Edition, June 30, 2002). Readers should consult the COGE Handbook for additional explanation and guidance. Certain other terms used in this Annual Information Form have the meanings assigned to them in NI 51-101 and CSA 51-324.

**Interests in Reserves, Production, Wells and Properties**

**"gross"** means:

- (i) in relation to the Company's interest in production or reserves, its "company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;
- (ii) in relation to wells, the total number of wells in which the Company has an interest; and
- (iii) in relation to properties, the total area of properties in which the Company has an interest.

**"net"** means:

- (i) in relation to the Company's interest in production or reserves, the Company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in those production or reserves;
- (ii) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and
- (iii) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

**"working interest"** means the percentage of undivided interest held by the Company in the oil and/or natural gas or mineral lease granted by the mineral owner, Crown or freehold, which interest gives the Company the right to "work" the property (lease) to explore for, develop, produce and market the leased substances.

### ***Reserves Categories***

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions which are generally accepted as being reasonable and shall be disclosed (see "Economic Assumptions" below)

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

**"Proved Reserves"** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves.

**"Probable Reserves"** are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves.

Other criteria that must also be met for the classification of reserves are provided in Section 5.4.4 of the COGE Handbook.

**"Economic Assumptions"** will be the forecast prices and costs (as defined below) used in the estimate.

### ***Development and Production Status***

Each of the reserves categories (Proved and Probable) may be divided into developed and undeveloped categories:

**"Developed Reserves"** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into Producing and Non-Producing.

**"Developed Producing Reserves"** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

**"Developed Non-Producing Reserves"** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

**"Undeveloped Reserves"** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (Proved, Probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered

from specific wells, facilities and completion intervals in the pool and their respective development and production status.

### ***Levels of Certainty for Reported Reserves***

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

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves; and
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves.

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

### ***Description of Price and Cost Assumptions***

**"Forecast prices and costs"** means future prices and costs that are:

- (i) generally accepted as being a reasonable outlook of the future; and
- (ii) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices or costs referred to in paragraph (i).

### ***Description of Exploration & Development Wells and Costs***

**"Development Costs"** means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the crude oil and natural gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;
- (ii) Drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
- (iii) Acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
- (iv) Provide improved recovery systems.

**"Development Well"** means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

**"Exploration Costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and natural gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

- (i) Costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");
- (ii) Costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
- (iii) Dry hole contributions and bottom hole contributions;
- (iv) Costs of drilling and equipping exploratory wells; and
- (v) Costs of drilling exploratory type stratigraphic test wells.

**"Exploration Well"** means a well that is not a development well, a service well or a stratigraphic test well.

**"Service Well"** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

#### **NON-GAAP MEASURES**

Management uses the industry benchmark operating netback to analyze financial and operating performance. This benchmark as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities. Operating netback is used by research analysts to compare operating performance and a company's ability to maintain current operations and meet the forecasted capital program. Operating netback is the net result of the Company's revenue net of realized gains and losses on financial instruments, and royalty, operating and transportation expenses.

#### **FORWARD LOOKING STATEMENTS**

Certain statements included in this Annual Information Form constitute forward-looking statements. All statements contained herein that are not clearly historical in nature are forward-looking, and the words "anticipate", "attempt", "believe", "expect", "estimate", "ensure", "plans", "focus", "strategy", "strive" and similar expressions are generally intended to identify forward-looking statements. Such statements represent Progress' internal projections, estimates, expectations, beliefs, plans, objectives, assumptions, intentions or statements about future events or performance. These statements are only predictions and involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward looking statements. Although the Company believes that the expectations reflected in the forward-looking statements are reasonable, no assurance can be given that these expectations will prove to be correct and such forward looking statements should not be unduly relied upon. Many factors could cause the Company's actual results to differ materially from those expressed or implied in any forward-looking statements made by, or on behalf of, the Company. Prospective investors should carefully consider the information contained under the heading "*Risk Factors*" in this Annual Information Form.

Forward-looking statements included or incorporated by reference in this short form prospectus include, but are not limited to, statements with respect to:

- the performance characteristics of the Company's oil and natural gas properties;
- anticipated finding and development costs, onstream costs and operating costs for the Company;
- the quantity of the Company's existing oil and natural gas reserves and resources;
- land expiries;
- abandonment and reclamation costs;
- the Company's capital expenditure and investment program and the timing, allocation and results therefrom;
- timing of development of undeveloped reserves;
- estimated working interest;
- tax horizon;
- the Company's dividend policy and payment of dividends;
- geologic and geographic expansion plans and the results therefrom;
- drilling, completion and tie-in plans, locations and inventory;
- the impact of changes in oil and natural gas prices on cash flow;
- expectations regarding the ability to raise capital and to add to reserves;
- anticipated exploration and development programs and operational results;
- oil and natural gas production levels and product mix and sources of their growth;
- the existence, operation and strategy of the Company's commodity price risk management program;
- the Company's business and acquisition strategy and the benefits to be derived therefrom;
- the Company's goal to deliver production and reserve growth from its internal exploration and development program inventory;
- the emergence of accretive growth opportunities;
- the Company's ability to fund debt maturities;
- future development and growth prospects;
- the source of funding for the Company's activities;
- determination of future quantities of oil and natural gas reserves and the size of and future net revenues therefrom;
- ability to meet current and future obligations;
- treatment under governmental regulatory regimes, including royalty rates and tax laws;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- receipt of governmental approvals;
- potential dispositions and acquisitions;
- dividend policy and the timing and payment of dividends;
- the estimated cash purchase price for the Acquired Assets (as defined herein); and
- completion of the Foothills Acquisition (as defined herein);
- realization of the anticipated benefits of acquisitions (including the Foothills Acquisition) and dispositions.

In addition, statements relating to "reserves" or "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

Forward-looking statements are based on the Company's current beliefs as well as assumptions made by, and information currently available to, the Company concerning, among other things:

- anticipated geological, reserves, operational and financial performance of the Company and its assets, including the Acquired Assets, the Company's plans, goals, strategies and prospects and the results therefrom are based on a variety of assumptions regarding, among other things, exchange and interest rates, commodity prices and royalty regimes, the impact of increasing competition, conditions in general economic and financial markets, availability of drilling and related equipment, availability of skilled labour, current technology, anticipated cash flow, anticipated production rates, anticipated reserves, the timing and amount of capital expenditures and the results therefrom, marketability of oil and natural gas, royalty rates, effects of regulation by governmental

agencies, costs of borrowing, transportation and infrastructure availability and development, onstream, operating and other costs;

- the operation and strategy of the Company's commodity price risk management program is based on a variety of assumptions including expectations regarding commodity prices, foreign exchange rates, production levels and conditions in general economic and financial markets;
- the source of funding for the Company's activities and the Company's ability to fund debt maturities are based on a variety of assumptions regarding the Company's operational and financial performance, capital expenditure requirements and conditions in general economic and financial markets;
- the amount of future cash dividends, if any, is based on a variety of assumptions, including expectations regarding commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens and foreign exchange rates; and
- the completion of the Foothills Acquisition is based on a variety of assumptions relating to, among other things, the timely receipt of required regulatory approvals and the satisfaction of other closing conditions in all material respects in accordance with the terms of the Acquisition Agreement (as defined herein);

Some of the risks and other factors which could cause results to differ materially from those expressed in the forward-looking statements contained in this short form prospectus and in certain documents incorporated by reference herein include, but are not limited to:

- general economic conditions in Canada and globally;
- fluctuations in the price of oil and natural gas, interest and exchange rates;
- operational risks in exploring for, developing and producing crude oil and natural gas;
- governmental regulation of the oil and gas industry, including environmental regulation;
- actions taken by governmental authorities, including increases in taxes and changes in government regulations and incentive programs;
- liabilities inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems;
- geology of oil and gas deposits;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- availability of sufficient financial resources to fund the Company's capital expenditures;
- unforeseen difficulties in integrating the Acquired Assets into the Company's operations;
- failure to complete the Foothills Acquisition in all material respects in accordance with the Acquisition Agreement, or at all;
- uncertainty of finding reserves, developing and marketing those reserves;
- unanticipated operating events which could reduce production or cause production to be shut in or delayed;
- incorrect assessments of the value of acquisitions;
- ability to locate satisfactory properties for acquisition or participation;
- shut-ins of connected wells resulting from extreme weather conditions;
- insufficient storage or transportation capacity;
- hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury;
- encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations;
- uncertainties inherent in estimating quantities of oil and natural gas reserves and cash flows to be derived therefrom;
- failure to obtain industry partner and other third party consents and approvals, as and when required;
- stock market volatility and market valuations;
- competition for, among other things, capital, acquisition of reserves, undeveloped land and skilled personnel;
- the availability of capital on acceptable terms;
- fluctuations in the costs of borrowing;
- the use of derivative financial instruments;
- political or economic developments;
- ability to obtain regulatory approvals;
- the occurrence of unexpected events; and

- the results of litigation or regulatory proceedings that may be brought against the Company.

Management has included the above summary of assumptions and risks related to forward-looking statements provided in this short form prospectus and the documents incorporated by reference herein in order to provide Shareholders with a more complete perspective on the Company's future operations. Readers are cautioned that this information may not be appropriate for other purposes.

**Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statement disclosure contained in this Annual Information Form are expressly qualified by this cautionary statement.**

These forward-looking statements are made as of the date of this Annual Information Form and the Company disclaims any intent or obligation to update publicly any forward-looking statements, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

## **PROGRESS ENERGY RESOURCES CORP.**

### **General**

Progress is engaged in the exploration for, and the acquisition, development and production of, oil and natural gas reserves in the provinces of British Columbia and Alberta. The Company is the resulting entity following the combination of the Trust and ProEx on January 15, 2009 into a new public entity under the name of "Progress Energy Resources Corp." pursuant to the Arrangement. See "Description of the Business – Creation of Progress".

The Trust was an open-end unincorporated energy investment trust established pursuant to the laws of the Province of Alberta and created pursuant to the Progress Trust Indenture. The Trust was dissolved on January 15, 2009 pursuant to the Arrangement. ProEx was incorporated under the name 1101890 Alberta Ltd. pursuant to the ABCA on April 8, 2004. On May 27, 2004, ProEx filed Articles of Amendment to change its name to ProEx Energy Ltd. On June 29, 2004, ProEx filed Articles of Amendment to remove the "private company" restrictions from its Articles. On January 15, 2009 in connection with the Arrangement, ProEx filed Articles of Amalgamation to effect an amalgamation of ProEx and a wholly-owned subsidiary and Articles of Amendment to change its name to Progress Energy Resources Corp.

The Company's head office is located at Suite 1200, 205 – 5<sup>th</sup> Avenue S.W., Calgary, Alberta, T2P 2V7 and its registered office is located at Suite 1400, 350 – 7<sup>th</sup> Avenue S.W., Calgary, Alberta, T2P 3N9.

The Company currently has one wholly owned subsidiary and is a partner in the Partnership. See "*Inter-Corporate Relationships*" below.

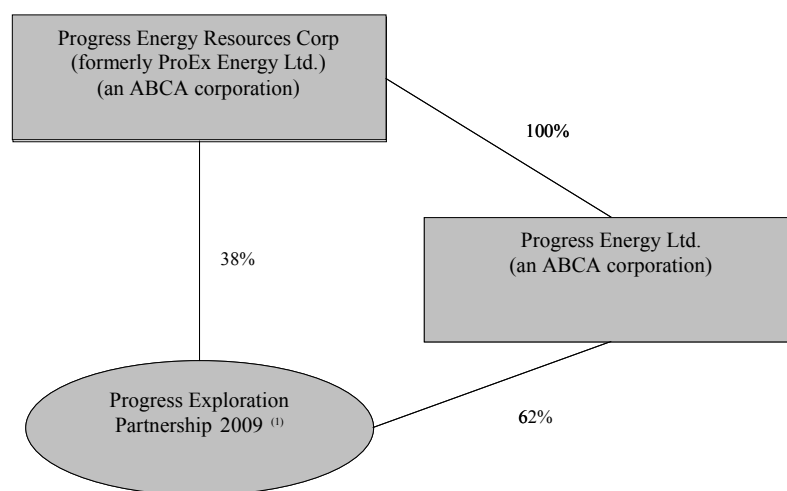
### **Inter-Corporate Relationships**

The following table provides the name, the percentage of voting securities owned by the Company, either direct or indirect, and the jurisdiction of incorporation of the Company's subsidiary and partnership as at the date hereof.

	<b>Percentage of voting securities (directly or indirectly)</b>	<b>Jurisdiction of Incorporation or Formation</b>
Progress Energy Ltd.	100%	Alberta
Progress Exploration Partnership 2009	100%	Alberta

## Corporate Structure

The following diagram illustrates the current organizational structure of the Company.



Note:

- (1) The Partnership is an Alberta general partnership created pursuant to the Arrangement which holds all of the oil and natural gas assets of the Company and Progress Energy Ltd.

## DESCRIPTION OF THE BUSINESS

### Progress Energy Resources Corp.

The Company is a mid-size exploration, development and production company with core areas in Alberta and British Columbia. The Company's focus is on natural gas and light oil projects, placing strong emphasis on efficient discovery and production of reserves yielding long term profitable growth while also intending to provide quarterly dividends to Shareholders. The Company's strategy is to deliver production and reserve growth on an annual basis from its internal exploration and development program inventory. The capital program would be supplemented with consolidating and on-trend acquisitions, opportunity-driven core area acquisitions and significant exploratory partnerships that would be regionally complementary to the Company's focused areas when these can be accomplished on economic terms. Refer to Appendix A-3 for a description of the Company's oil and gas assets and operations.

The Company strives to manage its capital deployment risk by ensuring that the majority of prospects have multi-zone potential; activity is focused in its core regions where the Company's expertise and experience is greatest; the number of wells drilled is large enough to increase the probability of statistical success rates; and high working interests in new prospects and geophysical techniques are utilized where appropriate. The Company funds its exploration and development program with cash flow, additional debt and strategic use of new equity where and when it believes is appropriate.

The Shares trade on the TSX under the symbol PRQ. The First Debentures, Second Debentures and Third Debentures trade on the TSX under the symbols PRQ.DB, PRQ.DB.A, and PRQ.DB.B, respectively.

### Creation of Progress

Progress (formerly ProEx) commenced operations on July 2, 2004 through the closing of a plan of arrangement between Progress Energy Ltd., Cequel, the Trust, Progress and Cyries. Pursuant to this plan of arrangement, Progress received interests in certain oil and natural gas properties formally owned by Progress Energy Ltd. including a 20 percent ownership of certain of Progress Energy Ltd.'s interest in oil and natural gas properties in the

Fort St. John Plains region of northeast British Columbia, a 100 percent ownership in Progress Energy Ltd.'s interest at Halkirk, Alberta and an 80 percent ownership in certain undeveloped lands in the Foothills region of northeast British Columbia. These properties produced approximately 1,000 BOE/d of natural gas and liquids on July 2, 2004 and they also contained approximately 52,000 net acres of undeveloped land and 79,000 acres of option land on which a sizeable prospect inventory had been identified.

On January 15, 2009, Progress, the Trust, Progress Energy Ltd. and certain other parties completed the Arrangement, which resulted in the combination of the Trust and Progress into a new public entity under the name of "Progress Energy Resources Corp." with the former owners of the Trust owning approximately 61% of the Company and the former owners of Progress owning approximately 39% of the Company.

Pursuant to the Arrangement, Progress acquired all of the issued and outstanding Units of the Trust and all of the issued and outstanding Exchangeable Shares. Holders of Units received, for each Unit held, 0.8125 of a Share. Holders of Exchangeable Shares received that number of Shares for each Unit that equalled the product of 0.8125 multiplied by the exchange ratio of each Exchangeable Share into Units at the relevant time (1.62092 Units for each Exchangeable Share). In addition, the Trust and ProEx entered into a distribution of assets and assumption of liabilities agreement whereby the Trust was liquidated and dissolved and the Company received all of the assets and assumed all of the liabilities of the Trust, including all of the covenants and obligations of the Trust in respect of the First Debentures and the Second Debentures. As a result, holders of First Debentures and the Second Debentures are now entitled to receive 0.8125 of a Share in lieu of each Unit that the holder was previously entitled to receive on conversion.

In accordance with GAAP, the Arrangement was accounted for as a reverse takeover, whereby the Trust is deemed the acquirer of Progress. The total consideration of the reverse takeover was approximately \$663.5 million based on the notional issuance of 73,479,481 Units at \$9.26 per Unit using the weighted average trading price of the Trust for a period before and after the announcement date of November 17, 2008, adjusted for the effect of normal issue costs, and estimated transaction costs of \$10.3 million.

### **Environment, Health and Safety**

Progress places a high priority on preserving the quality of its environment and protecting the health and safety of its employees, contractors and the public in communities in which it lives and works. Progress actively participates in industry-recognized programs at the highest possible levels in an effort to support continuous improvement. In this regard, Progress:

- Maintained a Platinum membership in the Environment, Health and Safety Stewardship Program developed by the Canadian Association of Petroleum Producers. Progress' participation requires its commitment to continuous improvement in its environment, health and safety management practices including sound planning and implementation, open communication, demonstrated performance and a thorough external audit of its activities every 3 years.
- Implemented an online safety orientation training system, developed and implemented new resource road guidelines, conducted emergency response preparedness drills and continues to develop its site specific work procedures and social responsibility policies.
- Maintained an active site abandonment and reclamation program which has resulted in six reclamation certificates being received in 2009, 30 Phase I, 15 Phase II and 70 detailed site assessments being completed and have 52 sites which are now ready to apply for reclamation certification.
- Developed a fugitive emissions strategy and is moving forward with full implementation across all operations.

Progress continually works to improve its health and safety performance through increased awareness in the field by frequently communicating safety responsibilities to its employees and contractors and by issuing and sharing safety information. Health and safety is increasingly more visible in the field and Progress has become more active with

contractor safety management through industry committee participation and the promotion of industry recognized best practices.

In 2009, Progress' overall health and safety performance improved compared to 2008. There was no employee lost time incidents in 2009 or 2008. There were a total of six recorded injury incidents in 2009 compared to fifteen in 2008. Progress' contractors had four lost-time incidents in 2009 compared to four in 2008.

### **Insurance**

The ownership and operation of crude oil and natural gas wells, pipelines and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to the Company's natural gas and crude oil properties and assets, as well as possible liability to third parties. The Company may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce the cash flow of Progress. Progress employs prudent risk management practices and maintains suitable liability insurance, where available. Business interruption insurance is also purchased for selected facilities, to the extent that such insurance is reasonably available.

### **Personnel**

Prior to the completion of the Arrangement, Progress had no full-time employees. Progress had access to technical and administrative staff through a technical services agreement with Progress Energy Ltd., administrator of the Trust. As at December 31, 2009 the Trust employed a total of 112 employees which became employees of Progress upon completion of the Arrangement.

## **GENERAL DEVELOPMENT OF THE BUSINESS**

### **Three Year Historical Overview**

#### **2007**

On April 2, 2007 Progress acquired certain interests in northeast British Columbia Foothills assets previously acquired by the Trust (the "Asset Acquisition"). Progress' total consideration, including transaction costs of \$0.9 million was \$136.4 million. The Asset Acquisition was financed through an equity offering of 8,050,000 Shares at a price of \$12.45 per Share for aggregate gross proceeds of \$100.2 million (\$95.6 million net of issue costs). The remainder of the purchase price was financed through increased bank debt. The Asset Acquisition included approximately 2,000 BOE/d of production, 95 percent natural gas and approximately 80,000 net acres of undeveloped land.

On September 12, 2007 Progress issued 1,830,000 Shares at a price \$13.70 per Share and 1,420,000 Shares on a "flow-through" basis pursuant to the Tax Act at a price of \$17.65 per Share. The aggregate proceeds, net of share issue costs of \$2.3 million were \$47.8 million. The proceeds from the offering were used to fund the Company's ongoing capital program.

On November 30, 2007 Progress purchased certain assets in the Blair and Cameron areas in the Foothills region. The net cost of the acquisition was \$14.3 million and included approximately 32,000 net acres of undeveloped land and 250 BOE/d of production. Progress acquired a 40 percent working interest in the acquired lands and the Trust acquired a 10 percent working interest. This acquisition was funded under the Company's credit facility.

During 2007, Progress carried out a \$150.2 million capital program with the majority of expenditures taking place in the Foothills region.

**2008**

On December 16, 2008 the Company issued 1,850,000 Shares on a "flow-through" basis pursuant to the Tax Act at a price of \$16.25 per Share for aggregate proceeds, net of share issue costs of \$1.4 million, of \$28.6 million. The proceeds from the offering were used to fund the Company's ongoing capital program. During 2008, Progress carried out a \$211.9 million capital program with the majority of expenditures taking place in the Foothills region.

**2009**

On January 15, 2009, Progress, the Trust, Progress Energy Ltd. and certain other parties completed the Arrangement, which resulted in the combination of the Trust and Progress. See "*Description of the Business – Creation of Progress*".

On February 18, 2009, Progress issued 12,950,000 Shares at a price of \$10.85 per Share for aggregate proceeds, net of share issue costs of \$6.7 million, of \$133.8 million. The proceeds from the offering were used to fund the Company's ongoing capital program.

On October 23, 2009, the Company issued \$200 million principal amount of Third Debentures. Interest is paid semi-annually on April 30 and October 31 and the Third Debentures mature on October 31, 2014. Each Third Debenture may be converted to Shares at the option of the holder at a conversion price of \$18.00 per Share. The proceeds of the offering were initially used to reduce outstanding bank indebtedness thereby freeing up borrowing capacity to fund a portion of the Company's ongoing capital program.

During 2009, the Company carried out a \$190.0 million capital program. The focus of the program was to continue with the Company's success in the Nikanassin formation in the Deep Basin region of northwest Alberta and establish a development program in the Montney formation in the Foothills region of northeast British Columbia.

During 2009, the Company declared quarterly dividends which totalled \$67.8 million or \$0.40 per Share for the year ended December 31, 2009. On August 28, 2009 Progress implemented a dividend reinvestment plan ("**DRIP**") whereby Shareholders can elect to receive their dividend in Shares. The number of Shares to be issued is based on 95 percent of the "average market price" being the weighted average trading prices of the Shares for the five consecutive trading days before the dividend payment date. In 2009, 105,914 Shares were issued under the DRIP and on January 15, 2010 the Company issued 97,206 Shares in payment of \$1.3 million of dividends to Shareholders who elected to participate in the DRIP for the dividend for the period from October 1, 2009 to December 31, 2009. Progress intends to pay quarterly dividends, however these dividends are not guaranteed. See "*Risk Factors*".

**Significant Acquisitions**

Progress did not complete any significant acquisitions for which disclosure is required under Part 8 of NI 51-102 during the most recently completed financial year. Since the Arrangement was a reverse takeover, in accordance with Part 8 of NI 51-102, a business acquisition report was not filed for the Arrangement.

**RECENT DEVELOPMENTS*****Capital Program***

For 2010 the Company commenced phase one of its Montney development program in the Town South area. The capital program for 2010 has been set at approximately \$350 million. In the near term, the Company expects to invest \$125 million in the first quarter of 2010 on the drilling of approximately 30 wells.

***Foothills Acquisition***

On February 9, 2010, Progress entered into an agreement (the "Acquisition Agreement") to acquire certain petroleum and natural gas properties in the Foothills region of British Columbia (the "Acquired Assets") for a cash purchase price, at closing, of approximately \$390 million, prior to closing adjustments (the "Foothills Acquisition"). The Foothills Acquisition assets are immediately adjacent to the Company's producing assets in the Town, Bubbles

and Blueberry/Beg areas and represents a strategic fit with the Company's existing northeast British Columbia Foothills properties. The assets include production of approximately 7,300 BOE/d, 91 percent natural gas, and approximately 188,000 net acres of undeveloped land. The Foothills Acquisition has an effective date of January 1, 2010 and is expected to close on or about March 31, 2010. Certain of the lands are subject to rights of first refusal ("ROFRs"). ROFR lands constitute approximately 25 percent of the total current production and proved reserves at December 31, 2009 of the Acquired Assets and a value of approximately 58% of the purchase price of the Acquired Assets, with the higher proportion due to the additional value ascribed by the Company to certain undeveloped lands and the potential upside of the Acquired Assets as a whole and in particular the properties subject to ROFRs.

The Company has paid deposit of \$39 million to the vendor of the Acquired Assets. In accordance with the terms of the Acquisition Agreement, if the Acquisition is completed, the deposit will be credited to the purchase price. If the Acquisition does not occur for any reason other than a default by the vendor of the Acquired Assets under the Acquisition Agreement or the failure of the vendor to comply with, or the non-satisfaction of, the conditions precedent to closing in Progress' favour, then the vendor will be entitled to retain the deposit (together with interest thereon). If the closing does not occur because of a default by the vendor under the Acquisition Agreement or the failure of the vendor to comply with, or the non-satisfaction of, the conditions precedent to closing in favour of Progress, the deposit (together with the interest thereon) will be returned to Progress.

The Company intends to fund the purchase price of the Acquired Assets and a portion of the Company's 2010 capital investment program through: (i) a \$350 million subscription receipt private placement (the "**Private Placement**") with the CPPIB of 27,780,000 subscription receipts ("**Placement Subscription Receipts**") at \$12.60 per Placement Subscription Receipt; and (ii) a \$250 million subscription receipt public offering (the "**Public Offering**") of 19,850,000 subscription receipts (the "**Offering Subscription Receipts**") at a price of \$12.60 per Offering Subscription Receipt. The Private Placement and Public Offering were completed on March 2, 2010. Each Placement Subscription Receipt and each Offering Subscription Receipt (collectively, the "**Subscription Receipts**") represents the right to receive one Share of Progress, without the payment of any additional consideration, on the closing of the Foothills Acquisition in accordance with the terms of the agreements that govern the Subscription Receipts. The proceeds from the Private Placement and the Public Offering have been deposited in escrow pending the closing of the Foothills Acquisition. If the Foothills Acquisition closes on or before March 31, 2010 as currently contemplated, the escrowed proceeds will be released to the Company. If the closing of the Foothills Acquisition does not occur by April 30, 2010, then holders of Subscription Receipts will be entitled to receive the purchase price of their Subscription Receipts plus their pro rata share of interest earned thereon. The Placement Subscription Receipts are and the underlying Shares issued pursuant to the Private Placement will be subject to a statutory hold period, and CPPIB has agreed not to sell any of the Shares for 18 months following closing, unless otherwise approved by the Company.

In connection with the Private Placement, the Corporation entered into the Private Placement Agreement with the CPPIB pursuant to which the Company and CPPIB have agreed to certain matters in connection with CPPIB's investment in the Company. The following is a summary of the material terms of these rights as set forth in the Private Placement Agreement.

#### *Nomination Rights*

For so long as CPPIB owns more than 12.5% of the outstanding Shares, CPPIB will have the right to nominate one representative as a director of the Company, provided that such nominee is acceptable to the Board of Directors, acting reasonably.

#### *Registration Rights*

The Private Placement Agreement provides for so long as CPPIB holds 10% or more of the outstanding Shares on a non-diluted basis, CPPIB may require the Company to prepare, file and obtain a receipt for a final prospectus under applicable securities legislation in Canada qualifying for distribution of some or all of the Shares or other securities of the Company held by CPPIB, such right to be exercised in only two instances and subject to certain restrictions. In addition, after the expiry of 18 months following the issuance of the Private Placement Receipts, the Company will be required under certain circumstances to qualify for distribution the Shares owned by CPPIB in a prospectus offering otherwise being undertaken by the Company to the extent of 15% of such offering.

### *Subscription Rights*

Pursuant to the Private Placement Agreement, for so long as CPPIB owns greater than 10% of the outstanding Shares, it shall have the right to participate in future offerings of securities by the Company, whether by way of public offering or private placement basis, including any offering of Shares, securities convertible or exchangeable into Shares, up to CPPIB's pro-rata ownership interest immediately prior to such offering in the case of a public offering, in order to maintain its pro rata percentage ownership interest in the Company, and up to all of the offering in the case of a private placement.

### ***Dividends***

On February 9, 2010, the Board of Directors announced that the first quarter dividend will be maintained at \$0.10 per Share. The dividend will be payable on April 15, 2010 to Shareholders of record as of March 31, 2010.

### ***Outlook***

Including the Foothills Acquisition, production for 2010 is expected to average approximately 40,000 to 42,000 BOE/d. The Company's capital investment program has been set at approximately \$350 million with a primary focus on the Montney and Nikanassin plays in the Foothills and Deep Basin regions. Approximately 75 percent of capital will be invested in drilling and completions activities, 15 percent on major facilities and 10 percent on land and seismic. The production mix for 2010 is expected to be 88 percent natural gas, five percent crude oil and seven percent natural gas liquids.

## **VOTING UNITS AND PRINCIPAL HOLDERS THEREOF**

The Company is authorized to issue an unlimited number of Shares.

Holders of Shares are entitled to one vote per share at meetings of holders of Shares. Subject to the rights of the holders of any shares having priority over the Shares, Shareholders are entitled to receive dividends if, as and when declared by the Board of Directors and upon liquidation, dissolution or winding-up, to receive the remaining property of the Company. As at March 5, 2010, there were 165,381,418 Shares issued and outstanding.

## **INDUSTRY CONDITIONS**

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

### **Pricing and Marketing**

#### *Oil*

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "NEB"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires

an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

### *Natural Gas*

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m<sup>3</sup>/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

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

### **Pipeline Capacity**

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

### **The North American Free Trade Agreement**

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States, and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon 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 voluntary measures which only restrict the volume of exports; and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, that any prohibition in any circumstances in which any other form of quantitative restriction is applied is prohibited, and in the case of import-price requirements, that such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes, minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

### **Royalties and Incentives**

#### *General*

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates, and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity,

geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

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

### ***Alberta***

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime; which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF range from 0-50%, an increase from the previous maximums of 30-35% depending on the vintage of the oil, and rate caps are set at \$120 per barrel.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF range from 5-50%, an increase from the previous maximums of 5-35%, and rate caps are set at \$17.75/GJ.

Oil sands projects are also subject to the NRF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil: rates are 1% when the market price of oil is less than or equal to \$55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at \$120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net Revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above \$55 up to 40% when oil is priced at \$120 or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a \$200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a \$1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to \$3,750 per meter.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price

levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF and wells that operated under the transitional royalty rates will revert to royalty rates determined by the NRF.

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

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

### ***British Columbia***

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

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

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

As at the beginning of 2009, British Columbia maintained a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to \$100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;
- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres spud between December 1, 2003 and September 1, 2009;
- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;
- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m<sup>3</sup> of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;
- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m<sup>3</sup> as well as a royalty credit for coalbed gas wells equal to \$50,000 for wells drilled on Crown land and a tax credit equal to \$30,000 for wells drilled on freehold land;
- *Marginal Royalty Reduction Program* providing royalty breaks for low productivity natural gas wells with average monthly production under 25,000 m<sup>3</sup> during the first 12 production months and average daily production less than 23 m<sup>3</sup> for every metre of marginal well depth;
- *Ultra-Marginal Royalty Reduction Program* providing additional royalty breaks for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m<sup>3</sup> during the first 12 production months and average daily production less than 11.5 m<sup>3</sup> (development wells) or 17 m<sup>3</sup> (exploratory wildcat wells) for every 100 metres of marginal well depth;
- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

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

On March 2, 2009, the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which allocates \$120 million in royalty credits for oil and gas companies. The Infrastructure Royalty Credit Program 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.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 m. Wells spud between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief

Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An additional \$50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

### **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 from two years 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 and British Columbia 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.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides, for the first time in western Canada, for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

### **Environmental Regulation**

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

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations in order for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals

of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

## **Climate Change Regulation**

### ***Federal***

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

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark from December 6 to 18, 2009 (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord 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. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

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

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

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both greenhouse gases and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have recently indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. The approach of the United States is expected to include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the Updated Action Plan. As a result, many provisions of the Updated Action Plan, described below, are expected to be significantly modified.

The stated goal of the Updated Action Plan, as currently drafted, is to reduce greenhouse gas emissions to 20% below 2006 levels by 2020 and 60-70% by 2050. As noted above, the goal has now been modified by the Government of Canada. 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 applied to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

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

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO<sub>2</sub> equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO<sub>2</sub> equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 BOE/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors govern 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: Technology Fund contributions, offset credits, clean development credits and credits for early action. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at \$15 tonnes per CO<sub>2</sub> equivalent for the 2010-12 period, rising to \$20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

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

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

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

### *Alberta*

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on July 1, 2007, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to comply with the CCEMA. Similarly to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Existing Facilities" and "New Facilities". Existing Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2008 or that have completed 8 or more years of commercial operation. Existing Facilities were required to reduce their emissions intensity by March 31, 2008 by 12% from a baseline established by their average emissions intensity between 2003 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation subsequent to December 31, 2008, have completed less than 8 years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are also required to reduce their emissions intensity by 12% but this target is based on the emissions intensity of the facility in its third year of commercial operation and does not apply during the first 3 years of operation of the New Facility. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements beyond the 12% emissions intensity required.

The CCEMA contains similar compliance mechanisms as the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of \$15 per tonne of CO<sub>2</sub> equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reduction in accordance with established protocols published by the Government of Alberta. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

### *British Columbia*

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at \$10 per tonne of CO<sub>2</sub> equivalent and rose to \$15 per tonne of CO<sub>2</sub> equivalent on July 1, 2009. It is scheduled to further increase at a rate of \$5 per tonne of CO<sub>2</sub> equivalent on July 1 of every year until it reaches \$30 per tonne of CO<sub>2</sub> equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and will come into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on greenhouse gas emissions. It is expected that greenhouse gas emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO<sub>2</sub> equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in greenhouse gas emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2009, new reporting regulations will come into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO<sub>2</sub> equivalents per year to be reporting their emissions.

## RISK FACTORS

*The Company is engaged in the exploration, development, production and acquisition of crude oil and natural gas. These activities involve a number of risks and uncertainties inherent in the industry, some of which are summarized below. Additional risks and uncertainties that our management may be unaware of, or that they determine to be immaterial may also become important factors which affect the Company.*

### Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. Although economic conditions improved towards the latter portion of 2009, these factors have negatively impacted company valuations and may impact the performance of the global economy going forward.

### Exploration and Development

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Company will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry 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.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although the Company maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company 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 the Company's business, financial condition, results of operations and prospects.

### **Operations**

Progress' operations are subject to all of the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, blow outs, craterings and fires, all of which could result in personal injuries, loss of life and damage to the property of Progress and others. Progress has both safety and environmental policies in place to protect its operators and employees, as well as to meet the regulatory requirements in those areas where it operates. In addition, Progress has liability insurance policies in place, in such amounts, as it considers adequate. Progress will not be fully insured against all of these risks, nor are all such risks insurable. See "Risk Factors—Insurance".

Continuing production from a property, and/or, to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of Progress to certain properties.

Progress is also subject to deliverability uncertainties related to the proximity of its reserves to pipeline and processing facilities, continued capacity and access at a limited number of processing facilities and the possible inability to secure space on pipelines which deliver oil and natural gas to commercial markets.

### **Operational Dependence**

Other companies operate some of the assets in which the Company has an interest. As a result, the Company has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Company's financial performance. The Company's return on assets operated by others therefore depends upon a number of factors that may be outside of the Company's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

### **Capital Markets**

As a result of the weakened global economic situation, the Company, along with all other oil and gas entities, will have restricted access to capital and increased borrowing costs. Although the Company's business and asset base have not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of cash flow from operations, borrowings and possible future equity sales, the Company's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and the Company's securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

Based on current funds available and expected cash flow generated from operations, the Company believes it has sufficient funds available to fund its projected capital expenditures. However, if cash flow from operating activities is lower than expected or capital costs for these projects exceed current estimates, or if the Company incurs major unanticipated expenses related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for

the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

### **Credit Facility Risk**

The Company currently has a \$650 million syndicated credit facility with eight financial institutions (the "Credit Facility"). At the option of the Company, the lenders will review the Credit Facility each year and determine if they will extend for a further 364 day period. An extension will only be granted for those lenders who approve the extension, and only if lenders holding two-thirds of the total commitment agree to extend. In the event that the Credit Facility is not extended for a particular lender or lenders, then all indebtedness under the Credit Facility owing to those non-extending lenders will be repayable one year later. The current renewal date is March 31, 2010 (making the current maturity date March 31, 2011 if no extension were to be granted by any lender). There is also a risk that the Credit Facility will not be renewed for the same or on the same terms. Any of these events could affect the Company's ability to fund ongoing operations.

The Credit Facility is a "borrowing base" facility, meaning that the amount of available credit is dependent in part on the reserves attributable to the Company's assets. A sustained material decline in prices of oil and natural gas could materially reduce the Company's borrowing base, thereby reducing the bank credit available to the Company and possibly causing a portion of such bank debt to be required to be repaid. The borrowing base is generally re-determined by the lenders semi-annually and upon the acquisition or disposition of assets beyond certain defined limits. The borrowing base is scheduled for review in the first quarter of 2010 and there can be no assurance that the current borrowing base level of the Company will be maintained.

At January 31, 2010, approximately \$55.7 million aggregate principal amount of First Debentures were outstanding, \$75.0 million aggregate principal amount of Second Debentures were outstanding and \$200.0 million aggregate principal amount of Third Debentures were outstanding. The First Debentures are due June 30, 2010, the Second Debentures are due September 30, 2011 and the Third Debentures are due October 31, 2014. The Company intends to fund these debt maturities with the Credit Facility. In the event the Company is unable to refinance its debt obligations it may impact the Company's ability to fund its ongoing operations.

The Company is required to comply with covenants under the Credit Facility. In the event that the Company does not comply with covenants under the Credit Facility, the Company's access to capital could be restricted or repayment could be required. The Company routinely reviews the covenants based on actual and forecast results and has the ability to make changes to its development plans and/or dividend policy to comply with covenants under the Credit Facility.

### **Prices, Markets and Marketing**

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by numerous factors beyond its control. The Company's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of

foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

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

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

### **Hedging**

From time to time the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Company will not benefit from the fluctuating exchange rate.

### **Additional Funding Requirements**

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Company may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Company's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Company. Continued uncertainty in domestic and international credit markets could materially affect the Company's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Company's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

### **Capital Investment**

The timing and amount of capital expenditures will directly affect the amount of income for available for future dividends to Shareholders. Dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are made.

### **Availability of Drilling Equipment and Access**

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

**Title to Assets**

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Company's claim which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

**Reserve Estimates**

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

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

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

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

**Competition**

The petroleum industry is competitive in all its phases. The Company competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Company. The Company's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

## **Environmental**

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it will be in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Company's business, financial condition, results of operations and prospects. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition. See "*Industry Conditions – Environmental Regulation*".

## **Climate Change**

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. The result of such meeting was the Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol. The Company's exploration and production facilities and other operations and activities emit greenhouse gases and require the Company to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*. The Company will also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which are now expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition. See "*Industry Conditions – Climate Change Regulation*".

## **Insurance**

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

the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

### **Delay in Cash Distributions**

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the properties, and by the operator to Progress, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of the properties, or the establishment by the operator of reserves for such expenses. Accordingly, the ability of Progress to pay timely dividends to Shareholders may be adversely affected.

### **Depletion of Reserves**

The Company has certain unique attributes that differentiate it from many other oil and gas industry participants. Distributions driven from the operation of oil and natural gas properties, absent commodity price increases or cost effective acquisition and development activities will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. Although Progress currently reinvests a portion of its cash flow to fund its exploration and development program, there can be no assurances that this will prevent a reduction in production and reserve levels.

Progress' future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on its success in its exploration and development projects, exploiting its reserve base and, if applicable, acquiring additional reserves. Without reserve additions through development or acquisition activities, Progress' reserves and production will decline over time as reserves are depleted.

To the extent that external sources of capital, including the issuance of additional Shares, become limited or unavailable, Progress' ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that Progress is required to use cash flow to finance capital expenditures or property acquisitions, future dividends may be reduced.

There can be no assurance that Progress will be successful in developing or acquiring additional reserves on terms that meet the Company's investment objectives.

### **Return of Capital**

Shares will have no value when reserves from the Company's oil and gas properties can no longer be economically produced and, as a result, dividends do not represent a "yield" in the traditional sense and are not comparable to bonds or other fixed yield securities, where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments. Dividends represent a blend of return of Shareholders initial investment and a return on Shareholders initial investment.

### **Variations in Foreign Exchange Rates and Interest Rates**

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Company's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Company's reserves as determined by independent evaluators.

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

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, which could negatively impact the market price of the Shares of the Company.

**Geo-Political Risks**

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Company's net production revenue.

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

**Dilution**

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

**Dividends**

Historical dividend payments of the Company may not be reflective of future dividend payments, which will be subject to review by the Board of Directors taking into account the prevailing financial circumstances of Progress at the relevant time. The actual dividend amount, if any, is at the discretion of the Board of Directors. Management monitors the Company's dividend policy with respect to forecasted net cash flow, debt levels and capital expenditures. As a crude oil and natural gas company, Progress has a declining asset base and therefore relies on ongoing development activities and acquisitions to replace production and add additional reserves. Progress' future crude oil and natural gas production and reserves are highly dependent on its success in exploiting its asset base and acquiring additional reserves. The success of these activities, along with natural gas prices are the main factors influencing the sustainability of the Company's dividends. Although Progress intends to continue to declare dividends to Shareholders, these dividends are not guaranteed.

**Changes in Legislation and Administrative Practices**

There can be no assurances that income tax laws and government incentive programs relating to the oil and gas industry will not be changed in a manner which materially adversely affects the Company and the Shareholders. There can be no assurance that the CRA will agree with how the Company calculates its income for tax purposes or that the CRA will not change its administrative practices to the detriment of the Company or the Shareholders.

**Debt Service**

Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service. Although it is believed that the bank lines of credit is sufficient, there can be no assurance that the amount will be adequate for the financial obligations of Progress or that additional funds can be obtained.

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

The Credit Facility contains restrictions on Progress' ability to pay dividends, including the declaration or payment of any dividend by the Company to Shareholders. Progress and its subsidiaries are restricted from paying dividends when (i) a default or event of default under the Credit Facility has occurred and is continuing, or (ii) outstanding loans under the Credit Facility exceed the borrowing base set by the lenders thereunder until such time as such outstanding loans are reduced below the borrowing base. The borrowing base is generally re-determined by the lenders on a semi-annual basis and upon the acquisition or disposition of assets beyond certain defined limits.

## **Regulatory**

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "*Industry Conditions*". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Company's costs, any of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Company will require licenses from various governmental authorities. There can be no assurance that the Company will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

## **Failure to Realize Anticipated Benefits of Acquisitions and Dispositions and of the Foothills Acquisition**

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

The Company is proposing to complete the Foothills Acquisition to strengthen its position in the oil and natural gas industry and to create the opportunity to realize certain benefits. Achieving the benefits of the Foothills Acquisition depends in part on successfully consolidating functions and integrating operations, procedures and personnel in a timely and efficient manner, as well as the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of the Acquired Assets requires the dedication of substantial management effort, time and resources, which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. The integration process may result in the loss of key employees and the disruption of ongoing business, customer and employee relationships that may adversely affect the Company's ability to achieve the anticipated benefits of the Foothills Acquisition.

Producing and non-producing oil and natural gas properties and related assets held by the vendor of the Acquired Assets subject to ROFRs constitute approximately 25% of the total current production and December 31, 2009 reserves of the Acquired Assets and a value of approximately 58% of the purchase price of the Acquired Assets, with the higher proportion due to the additional value ascribed by the Company to certain undeveloped lands and the potential upside of the Acquired Assets as a whole and in particular the properties subject to a ROFR. In addition, one single property constitutes almost all of the Acquired Assets subject to such ROFRs. To the extent that these third parties appropriately exercise such ROFRs, the Company will still be required to complete the Foothills Acquisition but will not acquire title to the properties subject to the ROFRs and will not be required to pay the portion of the purchase price to the vendor attributable to such properties. However, if the Foothills Acquisition is completed, the Subscription Receipts will be converted into Shares and the Company will receive the full amount of the proceeds from the Private Placement and the Public Offering, and a greater portion of the proceeds from such offerings will be used for capital expenditures, debt repayments and other corporate purposes in lieu of payment of the purchase price for those properties subject to the ROFRs. Such use of proceeds may not generate the additional cash flow that would have been generated from the properties for which the ROFR was exercised, and there can be no assurance that the Company will identify uses for such proceeds that will be as beneficial to the Company as the acquisition of the properties for which the ROFR was exercised that were not acquired by the Company.

**Possible Failure to Complete the Foothills Acquisition**

The Foothills Acquisition is subject to normal commercial risk that the Foothills Acquisition may not be completed on the terms negotiated or at all. In addition, if closing of the Foothills Acquisition does not take place as contemplated, the Company could suffer adverse consequences, including the forfeiture of the deposit or the loss of investor confidence.

**Conflicts of Interest**

Certain directors of the Company 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. See "*Directors and Officers*".

**Management of Growth**

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Company to deal with this growth may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

**Expiration of Licenses and Leases**

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

**Seasonality**

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Company.

**Third Party Credit Risk**

The Company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

**Reliance on Key Personnel**

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key person insurance in effect for the Company. The contributions of the existing management team to the immediate and near term operations of the Company are likely to be of

central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

### **Project Risks**

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

### **Substantial Capital Requirements**

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Company to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and prospects.

### **Issuance of Debt**

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

## Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Company is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

## MARKET FOR SECURITIES

### Common Shares

The Shares are listed and trade on the TSX and commenced trading under the new symbol "PRQ" following the completion of the Arrangement on January 21, 2009. The following table sets forth the trading history of the Shares since January 21, 2009.

	Price Range		Volume
	High (\$)	Low (\$)	
<b>2009</b>			
January (from January 21) .....	12.45	10.13	10,323,980
February.....	10.59	7.60	16,823,007
March.....	10.80	7.60	16,274,810
April.....	10.15	8.80	15,312,084
May.....	11.65	8.70	22,031,492
June.....	11.72	9.55	15,158,323
July.....	10.16	8.52	14,640,706
August.....	10.41	9.30	13,361,091
September.....	14.02	9.81	22,755,947
October.....	15.29	13.10	18,218,172
November.....	15.14	12.73	15,778,068
December.....	14.23	12.49	9,899,919
<b>2010</b>			
January.....	14.70	13.27	10,410,622
February.....	14.14	12.13	18,240,451
March (to March 5) .....	12.83	12.31	2,976,240

Prior to the completion of the Arrangement, the Shares were listed and traded on the TSX under the symbol "PXE". The following table sets forth the trading history of the Shares from January 1 to January 20, 2009.

	Price Range		Volume
	High (\$)	Low (\$)	
<b>2009</b>			
January (to January 20, 2009) .....	12.23	10.44	10,882,013

## First Debentures

The First Debentures are listed and trade on the TSX. The current trading symbol for the First Debentures is "PRQ.DB". Prior to the completion of the Arrangement, the First Debentures traded under the symbol "PGX.DB". The following table sets forth the trading history of the First Debentures since January 2009.

	Price Range		Volume
	High (\$)	Low (\$)	
<b>2009</b>			
January .....	98.00	91.00	76,430
February.....	97.25	96.25	34,040
March.....	99.00	95.00	20,570
April.....	99.98	96.50	11,040
May.....	101.00	98.02	16,030
June .....	101.00	99.02	7,600
July .....	101.38	99.95	9,840
August.....	102.00	101.00	8,240
September .....	102.00	100.51	11,170
October .....	102.00	101.12	10,830
November .....	102.18	101.12	7,470
December.....	102.18	101.50	3,490
<b>2010</b>			
January .....	102.10	101.00	17,590
February .....	101.74	101.25	18,760
March (to March 5) .....	101.70	101.36	3,220

## Second Debentures

The Second Debentures are listed and trade on the TSX. The current trading symbol for the Second Debentures is "PRQ.DB.A". Prior to the completion of the Arrangement, the Second Debentures traded under symbol "PGX.DB.A".

The following table sets forth the trading history of the Second Debentures since January 2009.

	Price Range		Volume
	High (\$)	Low (\$)	
<b>2009</b>			
January .....	91.00	84.00	23,850
February.....	93.00	88.00	120,030
March.....	95.00	89.75	9,220
April.....	96.00	89.50	10,370
May.....	98.00	96.00	11,790
June .....	98.00	92.05	83,760
July .....	99.00	96.00	23,720
August.....	100.30	98.00	18,620
September .....	100.30	99.50	13,530
October .....	101.39	99.00	46,960
November .....	104.50	100.50	11,860
December.....	103.00	100.25	6,340
<b>2010</b>			
January .....	102.75	101.00	2,320
February .....	103.01	101.80	4,250
March (to March 5) .....	104.50	102.75	1,210

### Third Debentures

The Third Debentures are listed and trade on the TSX. The trading symbol for the Third Debentures is "PRQ.DB.B".

The following table sets forth the trading history of the Third Debentures since their issue on October 23, 2009.

	Price Range		Volume
	High (\$)	Low (\$)	
<b>2009</b>			
October (from October 23) .....	102.40	100.00	323,575
November .....	103.00	98.25	158,560
December.....	101.00	98.50	173,900
<b>2010</b>			
January .....	104.70	101.00	210,490
February .....	103.25	100.00	291,630
March (to March 5) .....	101.89	100.62	8,510

### Offering Subscription Receipts

The Offering Subscription Receipts are listed and trade on the TSX. The trading symbol for the Offering Subscription Receipts is "PRQ.R".

The following table sets forth the trading history of the Offering Subscription Receipts since their issue on March 2, 2010.

	Price Range		Volume
	High (\$)	Low (\$)	
<b>2010</b>			
March (to March 5).....	12.64	12.29	1,138,450

### PRIOR SALES

On March 2, 2010, the Company issued 27,780,000 Private Placement Subscription Receipts at a price of \$12.60 per Private Placement Subscription Receipt. See "*Recent Developments – Foothills Acquisition*".

### DIVIDEND POLICY

Following completion of the Arrangement, the Company established a dividend policy of paying quarterly dividends to Shareholders, and the initial quarterly dividend of \$0.10 per Share was paid on April 15, 2009 to Shareholders of record on March 31, 2009. Since that time, the Company has paid a quarterly dividend of \$0.10 per Share to Shareholders of record on June 30, 2009, September 30, 2009 and December 31, 2009. The payment dates of the dividends were 15 days following the record date being July 15, 2009, October 15, 2009 and January 15, 2010, respectively. Subsequent to year end the Board of Directors declared that the 2010 first quarter dividend will be maintained at \$0.10 per Share. The dividend will be payable on April 15, 2010 to Shareholders of record as of March 31, 2010.

Prior to the completion of the Arrangement, Unitholders of the Trust of record on a distribution record date were entitled to receive distributions which were paid by the Trust to its Unitholders on the corresponding distribution payment date. The Trust had established the last day of each calendar month as a distribution record date with the 15th day of such month being the corresponding distribution payment date with December 31 being in all cases a distribution record date.

Starting in January 2007, the Trust reduced its monthly distributions from \$0.14 per Unit to \$0.10 per Unit due to a reduction in forecasted 2007 cash flow as a result of the then current weakness in natural gas prices. The Trust had

made cash distributions of \$0.14 per Unit on a monthly basis from July 2004 through to December 2006 and cash distributions of \$0.10 per Unit on a monthly basis from January 1, 2007 to December 2008.

The amount of future cash dividends, if any, is not assured and will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens and foreign exchange rates. See "*Risk Factors*".

The agreements governing the Credit Facility provide that if an event of default has occurred under the Credit Facility, the indebtedness may be accelerated by the lenders, and the ability to pay dividends to Shareholders thereupon ceases. The Company is restricted from making distributions (including the declaration of dividends) if it is in default under the Credit Facility (or a default would be expected to occur as a result of such distribution) or if its borrowings exceed its borrowing base threshold.

## DIRECTORS AND OFFICERS

The following table sets forth the names, province and country of residence, principal occupation, year of becoming a director or executive officer of Progress and the number of Shares beneficially owned, or controlled or directed, directly or indirectly, all as at February 28, 2010.

Name	Principal Residence	Position Presently Held	Principal Occupation	Director or Officer Since
David D. Johnson	Alberta, Canada	Executive Chairman and Director	Executive Chairman, Progress	July, 2004
Michael R. Culbert <sup>(5)</sup>	Alberta, Canada	President, CEO and Director	President & CEO, Progress	January, 2009
Donald F. Archibald <sup>(1)(4)</sup>	Alberta, Canada	Director	President, Cypress Energy Corp. (a private investment corporation)	January, 2009
John A. Brussa <sup>(3)(4)</sup>	Alberta, Canada	Director	Partner of Burnet, Duckworth & Palmer LLP	January, 2009
Howard J. Crone <sup>(1)(2)(4)</sup>	Alberta, Canada	Director	President & CEO, Cequence Energy Ltd.	January, 2009
Greg W. Kist <sup>(5)</sup>	Alberta, Canada	Vice President, Investor Relations and Marketing	Vice President, Investor Relations and Marketing, Progress	January, 2009
Art A. MacNichol <sup>(5)</sup>	Alberta, Canada	Vice President, Finance & Chief Financial Officer	Vice President, Finance & Chief Financial Officer, Progress	January, 2009
Brian A. McLachlan <sup>(2)(3)</sup>	Alberta, Canada	Director	President & CEO, Yoho Resources Inc.	July, 2004
Gary A. Miller <sup>(5)</sup>	Alberta, Canada	Vice President, Operations	Vice President, Operations, Progress	January, 2009
Gary E. Perron <sup>(1)(3)</sup>	Alberta, Canada	Director	Managing Director and Senior Vice President BMO Nesbitt Burns	July, 2004
Cindy R. Rutherford <sup>(5)</sup>	Alberta, Canada	Vice President, Land	Vice President, Land, Progress	January, 2009
James L. Stannard <sup>(5)</sup>	Alberta, Canada	Vice President, Engineering	Vice President, Engineering, Progress	January, 2009
Terrance D. Svarich <sup>(2)(4)</sup>	Alberta, Canada	Director	President, Devsun Ltd. (a private investment company)	July, 2004
Daniel C. Topolinsky <sup>(5)</sup>	Alberta, Canada	Senior Vice President, Exploration	Executive Vice President, Exploration and Development, Progress	January, 2009

## Notes:

- (1) Member of the audit committee.
- (2) Member of the reserve committee.
- (3) Member of the compensation committee.
- (4) Member of the corporate governance and nominating committee
- (5) Upon completion of the Arrangement, the officers of the Trust became officers of Progress. The officers had commenced their employment with the Trust as follows; Mr. Culbert – November, 2001; Mr. Kist - June, 2004; Mr. MacNichol - July, 2004; Mr. Miller - August, 2004; Mr. Stannard - June, 2002; Ms. Rutherford - April, 2002; and Mr. Topolinsky - May, 2002

As at February 28, 2010 the directors and executive officers of Progress, as a group, beneficially owned or controlled or directed, directly or indirectly, 15,715,693 Shares or approximately 10 percent of the issued and outstanding Shares.

The information as to the principal residence and occupation and as to Shares beneficially owned or controlled or directed directly or indirectly is based upon information provided by the directors and officers of Progress. The directors hold office until the next annual meeting of shareholders, currently scheduled for April 29, 2010 or until their successors duly elected.

The directors and officers listed above have held their principal occupations for in excess of five years except as follows. Prior to January 2009, all of the executive officers below held the same positions at the Trust. Prior to becoming officers of the Trust, the executive officers held the following positions.

Mr. Greg Kist was Manager, Investor Relations for EnCana Corporation from April 2002 to June 2004 and prior to that was Manager, Corporate Relations for Alberta Energy Company Ltd. ("AEC") from September 1997 to April 2002. Mr. Kist held various operations positions with AEC from March 1991 through August 1997, primarily in procurement. Mr. Art MacNichol was the Vice President of Finance and Chief Financial Officer of Calpine Natural Gas Trust from August 2003 to June 2004. Prior thereto, Mr. Art MacNichol was Vice President and Chief Financial Officer for Calpine Corporation's power and oil and gas operations in Canada and also held the position of Vice President and Chief Financial Officer of Calpine Power Ltd., manager of Calpine Power Income Fund. Mr. MacNichol held various positions with Encal Energy Ltd. from 1993 to April 2001 including that of Controller and Treasurer. Mr. Miller held the position of Director of Operations from May 2007 to February 2008, Manager, Operations from May 2005 to May 2007 and Manager, Production from July 2004 to May 2005 at Progress Energy Ltd. Mr. Miller was Production Superintendent, Qatar Petroleum from May 2001 to June 2004. Ms. Rutherford held the position Land Manager from May 2004 to May 2005 and Senior Landman from April 2002 to April 2004 at Progress Energy Ltd. Prior there to Senior Landman at Genesis Exploration Ltd/Vintage Petroleum Ltd. from July 2000 to March 2002 and Senior Landman at Ulster Petroleum Ltd. from February 1999 to May 2000. Mr. Stannard held the position of Director of Engineering from May 2007 to February 2008, Manager of Engineering from June 2004 to May 2007 and Senior Exploitation Engineer from June 2002 to June 2004 at Progress Energy Ltd. Mr. Topolinsky was President NXT Energy Ltd. from May 1999 to April 2002 and was Vice President Exploration at Renaissance Energy Ltd. from May 1996 to May 1999.

### **Corporate Cease Trade Orders or Bankruptcies**

Mr. David Johnson was a director of Merit Energy Ltd. from January 1995 until April 2000. While Mr. Johnson was a director, Merit Energy Ltd. experienced financial difficulties and was the subject of several lawsuits from shareholders and suppliers. Merit Energy Ltd. filed for and was granted an order pursuant to the *Companies' Creditors Arrangement Act* (Canada). Through this process, all claims and legal actions were settled and there were no outstanding claims remaining. As a director of Merit Energy Ltd., Mr. Johnson was also named in many of these claims; however, there are currently no outstanding claims against Mr. Johnson with respect to Merit Energy Ltd. or any other situation. Mr. John Brussa was a director of Imperial Metals Limited, a corporation engaged in both oil and gas and mining operations, in the year prior to that corporation implementing a plan of arrangement under the *Company Act* (British Columbia) and under the *Companies' Creditors Arrangement Act* (Canada) which resulted in the separation of its two businesses and the creation of two public corporations: Imperial Metals Corporation and IEI Energy Inc. (subsequently became Rider Resources Ltd.). The plan of arrangement was completed in April 2002.

Except as disclosed above, no director or executive officer is as at the date hereof, or has been, within 10 years of the date hereof, a director or chief executive officer or chief financial officer of any company, including Progress:

- (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; and
- (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, executive 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.

No current director or officer or securityholder holding a sufficient number of securities of Progress to affect materially the control of Progress has, within the last ten years prior to the date of this document, been a director or executive officer of any company (including Progress) 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 for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

In addition, no current director or officer or securityholder holding a sufficient number of securities of Progress to affect materially the control of Progress has, within the last ten years prior to the date of this document, 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 officer or securityholder holding a sufficient number of securities of Progress to affect materially the control of Progress 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.

### **Conflicts of Interest**

Directors and officers of Progress may, from to time, be involved with the business and operations of other oil and gas issuers, in which case a conflict may arise. See "*Risk Factors*".

### **ESCROWED SECURITIES**

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

### **AUDIT COMMITTEE INFORMATION**

#### **Audit Committee Mandate and Terms of Reference**

The Mandate and Terms of Reference of the Audit Committee of the Board of Director's is attached hereto as Appendix B. The members of the Audit Committee are Mr. Donald F. Archibald (Chairman), Mr. Howard Crone and Mr. Gary E. Perron.

#### **Composition of the Audit Committee**

The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate.

## Relevant Education and Experience

Mr. Donald Archibald, 49, has been the President of Cypress Energy Corp., a private investment company, since March 2008 and currently serves as chairman of Iteration Energy Ltd. and of Cequence Energy Ltd. Prior to this Mr. Archibald was the Chairman & Chief Executive Officer of Cyries from July 2004 to March 2008. Mr. Archibald was the President and Chief Executive Officer of Cequel from January 2002 to July 2004 and the President and Chief Executive Officer of Cypress Energy Inc. from 1995 to March 2001. He has considerable public company experience and holds a Bachelor of Commerce Degree and a Masters of Business Administration.

Mr. Howard J. Crone, 47, has been the President and CEO of Cequence Energy Ltd. since May 2009; prior thereto Mr. Crone was an independent businessman from July 2004 to May 2009. Prior to this he was Vice President, Corporate Development and Chief Operating Officer of Cequel from August 2003 to July 2004 and prior thereto was Vice President, Operations and Chief Operating Officer of Cequel from January 2002 to August 2003. Prior thereto Mr. Crone was Vice President, Operations and Chief Operating Officer of Cypress Energy Inc. from April 1996 to March 2001. He has a B.Sc. in Chemical Engineering and is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. Mr. Crone has considerable public oil and gas experience and serves as a director of several public companies.

Mr. Gary E. Perron, 54, is a Managing Director & Senior Vice President with BMO Nesbitt Burns Inc. and has provided investment advisory services for more than 29 years. He holds a Bachelor of Commerce Degree (Honours) and holds the Chartered Financial Analyst designation. Mr. Perron is Chairman of the Advisory Committee for the Norrep Group of funds which currently manages six public funds and four limited partnerships. Mr. Perron has considerable public oil and gas experience and serves as a director of several public companies.

## Pre-Approval of Policies and Procedures

We have a Non-Audit Services Policy that has been reviewed and approved by the Audit Committee. The Policy allows for pre-approval of audit services through the Audit Committee's review and approval of KPMG LLP's annual Audit Plan. For Audit Related, Tax and Other Non-Audit Services the policy allows for pre-approval of services that are recurring or reasonably expected to be provided. The policy provides that for services where the aggregate fees are estimated to be less than or equal to \$25,000 the Chief Financial Officer will obtain approval of the Chairman of the Audit Committee. Where the aggregate fees are estimated to be greater than \$25,000 the Chief Financial Officer will obtain approval of the Audit Committee. The Audit Committee is informed quarterly of the services provided by KPMG LLP.

## External Auditor Service Fees

### *Audit Fees*

The aggregate fees billed to Progress by KPMG LLP in 2009 and 2008 were as follows:

	2009	2008
Audit fees	280,000	132,000
Audit related services	119,000	46,000
Tax fees	4,000	-
All other fees	160,000	-
<b>Total</b>	<b>563,000</b>	<b>178,000</b>

The Audit Committee reviews the annual audit fees and considers the issue of auditor independence in the context of all services provided to the Company.

### *Audit and Related Fees*

The aggregate fees billed in each of the last two fiscal years for assurance related services by the Company's external auditor that are reasonably related to the performance of the audit or review of the Company's financial statements that are not reported under "Audit Fees" above were \$119,000 in 2009 and \$46,000 in 2008.

***Tax Fees***

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Company's external auditor for tax compliance, tax advice and tax planning were \$4,000 in 2009 and 2008.

***All Other Fees***

The aggregate fees billed in each of the last two fiscal years for products and services provided by the Company's auditors other than services reported above were \$160,000 in 2009 and \$nil in 2008, which in 2009 was primarily French translation services.

**LEGAL PROCEEDINGS AND REGULATORY ACTIONS**

There are no legal proceedings which Progress or any subsidiary of Progress is or was a party or of which any of their property is or was subject which are material to Progress and Progress is not aware of any such proceedings that are contemplated or pending. In addition, Progress was not subject to: (i) any penalties or sanctions imposed against it by a court relating to securities legislation or by a securities regulatory authority, or (ii) any other penalties or sanctions imposed by a court or regulatory body against it, or has entered into any settlement agreement with a court relating to securities legislation or with a securities regulatory authority.

**INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS**

There were no material interests, direct or indirect, of directors and executive officers of Progress, any persons or company that is the direct or indirect beneficial owner of, or who exercises control or direction over more than 10% of the outstanding Shares or any known associate or affiliate of such persons or companies, in any transaction within the three most recently completed financial years or during the last fiscal year or in any proposed transaction which has materially affected or would materially affect Progress except as otherwise disclosed herein or as otherwise publicly disclosed, including as described under the heading "*The Arrangement – Interests of Certain Persons or Companies in the Arrangement*" in the joint information circular – proxy statement of ProEx and Progress dated December 15, 2008 in connection with the Arrangement, which are incorporated herein by reference.

**INTERESTS OF EXPERTS**

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under NI 51-102 by Progress during, or related to, Progress' most recently completed financial year other than GLJ, Progress' independent engineering evaluator and KPMG LLP, Progress' auditors.

GLJ and its shareholders, as a group, own directly or indirectly less than 1% of the Progress' outstanding Shares. KPMG LLP has confirmed that they are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

## MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business and as set forth below, Progress has not entered into any material contracts within the most recently completed financial year or before the most recently completed financial year which is still in effect:

1. the Acquisition Agreement;
2. the Public Subscription Receipt Agreement; and
3. the Private Placement Subscription Receipt Agreement;
4. the Underwriting Agreement;
5. the Private Placement Agreement;
6. the credit agreement dated January 15, 2009 and the amendments thereto among Progress and certain lenders in respect of the Company's \$650 million syndicated credit facility, which agreement is described in note 5 to Progress' consolidated financial statements for the year ended December 31, 2009, which note is incorporated herein by reference; and
7. the Debenture Indentures and all supplements thereto governing the First Debentures, Second Debentures and Third Debentures.

Copies of these agreements are available on SEDAR at [www.sedar.com](http://www.sedar.com).

## TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Shares, First Debentures, Second Debentures, Third Debentures and Subscription Receipts is Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario.

## ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Progress' securities and securities authorized for issuance under equity compensation plans, where applicable, is contained in Progress' Information Circular Proxy Statement prepared in respect of the Annual Meeting of Shareholders to be held on April 29, 2010. Additional financial information is provided in Progress' comparative consolidated financial statements and management's discussion and analysis for the year ended December 31, 2009. For copies of the Information Circular – Proxy Statement, the consolidated financial statements and management's discussion and analysis, including any interim consolidated financial statements and additional copies of this Annual Information Form please contact:

Progress Energy Resources Corp.  
1200, 205 – 5th Avenue S.W.  
Calgary, Alberta  
T2P 2V7

Telephone: (403) 539-1809  
Toll free: 1-866-216-2150 (in Canada only)  
Facsimile: (403) 216-2514  
Email: [ir@progressenergy.com](mailto:ir@progressenergy.com)  
Website: [www.progressenergy.com](http://www.progressenergy.com)

Attention: Mr. Greg Kist  
Vice President, Investor Relations  
& Marketing

Alternatively, additional information relating to Progress may be found on SEDAR at [www.sedar.com](http://www.sedar.com).

**APPENDIX A-1  
REPORT OF MANAGEMENT AND DIRECTORS ON  
OIL AND GAS DISCLOSURE  
PROGRESS ENERGY RESOURCES CORP.**

**Report of Management and Directors on Reserve Data and Other Information (NI 51-101F3)**

Management of Progress Energy Resources Corp. (the "Company") is responsible for the preparation and disclosure of information with respect to the Company'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, 2009 estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserve data. The report of the independent qualified reserve evaluator is presented below.

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

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

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

- (a) the content and filings 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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

February 8, 2010

*(Signed)* "Michael R. Culbert"  
President and CEO

*(Signed)* "Howard Crone"  
Director & Chairman Reserves Committee

*(Signed)* "James L. Stannard"  
Vice President, Engineering

*(Signed)* "Terrance D. Svarich"  
Director & Member of the Reserves Committee

**APPENDIX A-2  
GLJ REPORT ON RESERVES DATA  
PROGRESS ENERGY RESOURCES CORP.**

**Report on Reserve Data (NI 51-101 F2)**

To the Board of Directors of Progress Energy Resources Corp. (the "Company"):

1. We have prepared an evaluation the Company's reserve data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, 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 forecasted 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, 2009, 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	Net Present value of Future Net Revenue (before income taxes, 10% discount rate) (\$000's)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	Corporate Summary February 4, 2010	Canada	-	\$1,885,721	-	\$1,885,721

5. In our opinion, the reserves data respectively evaluated by us have, in all material respect, been determined and are in accordance with the COGE Handbook.
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. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 8, 2010.

(Signed) Myron J. Hladyshevsky, P. Eng.  
Vice-President

**APPENDIX A-3**  
**STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION**  
**PROGRESS ENERGY RESOURCES CORP.**

The following tables set forth certain information relating to the Company's crude oil, natural gas and natural gas liquid reserves and the net present value of future net revenues associated with such reserves as at December 31, 2009, as evaluated by GLJ in the GLJ Progress Report based upon forecast price and cost assumptions. The GLJ Progress Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in CSA 51-324. GLJ was engaged to provide an evaluation of all of the Company's proved and proved plus probable reserves. Numbers in each column may not add due to rounding.

On January 15, 2009, Progress, the Trust, Progress Energy Ltd. and certain other parties completed the Arrangement, which resulted in the combination of the Trust and Progress into a new public entity under the name of "Progress Energy Resources Corp." with the former owners of the Trust owning approximately 61% of the Company and the former owners of Progress owning approximately 39% of the Company. In accordance with GAAP, the Arrangement was accounted for as a reverse takeover, whereby the Trust was deemed the acquirer of Progress and therefore, as a result, the reserves information presented below reflect the history of the Trust with Progress being the acquired reserves in 2009. Consequently, the opening balance of reserves reflects the Trust's reserves at January 1, 2009.

**All future net revenues are stated prior to provision for interest, general and administrative expenses and after deduction of royalties and estimated future capital expenditures. Future net revenues have been presented on both a before and after tax basis.**

**It should not be assumed that the present worth of estimated future cash flow presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of Progress' crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. Readers should review the definitions and information contained in "*Natural Gas and Petroleum Reserves and Production Information*" in conjunction with the following tables and notes.**

**Summary of Oil and Gas Reserves and Net Present Values of Future Net Revenue  
As of December 31, 2009  
Forecast Prices and Costs**

Reserve Category	Light and Medium Oil		Heavy Oil		Conventional Natural Gas		Natural Gas Liquids		BOE	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(Mbbbl)	(Mbbbl)	(Mbbbl)	(Mbbbl)	(MMcft)	(MMcft)	(Mbbbl)	(Mbbbl)	(MBOE)	(MBOE)
Proved										
Developed producing	2,887	2,467	505	425	364,582	299,934	5,078	3,635	69,234	56,516
Developed non- producing	328	290	16	16	47,889	38,670	607	439	8,933	7,190
Undeveloped	333	287	-	-	128,882	106,269	1,618	1,211	23,431	19,210
Total proved	3,549	3,044	521	441	541,352	444,873	7,302	5,285	101,597	82,916
Probable	1,046	880	122	98	288,356	238,917	3,436	2,497	52,663	43,294
Total proved plus probable	4,595	3,924	643	540	829,708	683,790	10,737	7,782	154,260	126,210

Net Present Value of Future Net Revenue											
Reserve Category	Before Income Taxes					After Income Taxes					BTNPV Disc 10% \$/BOE
	Discounted at (%/year)					Discounted at (%/year)					
	0	5	10	15	20	0	5	10	15	20	
(\$ thousands)											
<b>Proved</b>											
Developed Producing	1,866,143	1,339,129	1,062,863	892,160	775,422	1,848,370	1,335,370	1,061,973	891,929	775,358	18.81
Developed Non-Producing	243,262	166,916	124,935	99,106	81,849	182,446	142,511	114,447	94,330	79,565	17.38
Undeveloped	500,268	301,681	195,786	132,518	91,681	375,201	234,743	157,597	109,706	77,557	10.19
<b>Total Proved</b>	<b>2,609,672</b>	<b>1,807,726</b>	<b>1,383,584</b>	<b>1,123,784</b>	<b>948,953</b>	<b>2,406,017</b>	<b>1,712,624</b>	<b>1,334,017</b>	<b>1,095,965</b>	<b>932,479</b>	<b>16.69</b>
<b>Total Probable</b>	<b>1,709,762</b>	<b>840,024</b>	<b>502,137</b>	<b>335,649</b>	<b>240,287</b>	<b>1,282,319</b>	<b>635,427</b>	<b>384,917</b>	<b>261,371</b>	<b>190,211</b>	<b>11.60</b>
<b>Total Proved Plus Probable</b>	<b>4,319,434</b>	<b>2,647,749</b>	<b>1,885,721</b>	<b>1,459,433</b>	<b>1,189,240</b>	<b>3,688,336</b>	<b>2,348,051</b>	<b>1,718,934</b>	<b>1,357,336</b>	<b>1,122,690</b>	<b>14.94</b>

## Notes:

- (1) The estimated net present value of future net revenue is based on current legislation in place December 31, 2009.
- (2) Prices for oil F.O.B. Edmonton are based upon 40° API oil having less than 0.4% sulphur. Prices for natural gas are based upon a base pressure of 14.65 pounds per square inch and base temperature of 60°F. The wellhead oil prices were adjusted for quality and transportation based on historical actual prices. The natural gas prices were adjusted, where necessary, based on historical pricing based on heating values and the differing costs of service applied by various purchasers. The natural gas liquids prices were adjusted to reflect historical average prices received.
- (3) The forecast prices and cost case assumes no legislative or regulatory amendments and includes the effects of inflation. The estimated future net revenue to be derived from the production of the reserves includes an inflation rate of 2.0% per year, an exchange rate as listed below, and the following price forecasts supplied by GLJ, Progress' independent qualified reserves evaluator and are as noted below.

The undiscounted total future net revenue by reserves category as of December 31, 2009, using forecast prices and costs, is set forth below:

(\$ millions)								
Reserve Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Well Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
<b>Forecast Prices and Costs</b>								
Proved	5,122	912	1,240	319	42	2,610	204	2,406
Proved plus probable	8,203	1,441	1,881	510	52	4,319	631	3,688



<b>Year</b>	<b>NYMEX Futures Contract (US\$/MMBtu)</b>	<b>Midwest @ Chicago (US\$/MMBtu)</b>	<b>AECO Gas Price (Cdn\$/MMBtu)</b>	<b>Sumas Spot Gas Price (US\$/MMBtu)</b>
Forecast				
2010	6.00	6.10	5.96	5.60
2011	7.00	7.10	6.79	6.45
2012	7.10	7.20	6.89	6.55
2013	7.15	7.25	6.95	6.60
2014	7.35	7.45	7.05	6.80
2015	7.50	7.60	7.16	6.95
2016	7.75	7.85	7.42	7.20
2017	8.25	8.35	7.95	7.70
2018	8.79	8.89	8.52	8.24
2019	8.96	9.06	8.69	8.41
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

In 2009, Progress received a weighted average price of \$59.78 per Bbl for crude oil, \$42.05 per Bbl for NGL's and \$4.13 per Mcf for natural gas.

**Reconciliation of Gross Reserves by Principal Product Type  
Forecast Prices and Costs**

	Total Oil (Mbbl)	Light and Medium Oil (Mbbl)	Heavy Oil (Mbbl)	Natural Gas Liquids (Mbbl)	Total Natural Gas (Bcf)	Conventional Natural Gas (Bcf)	Coal Bed Methane (MMcf)	BOE (MM BOE)
<b>TOTAL PROVED</b>								
Opening Balance	3,764	3,265	499	4,690	318.99	317.83	1,162	61.62
Exploration discoveries	-	-	-	-	-	-	-	-
Drilling extensions and improved recovery	68	68	-	1,556	122.49	122.49	-	22.04
Infill Drilling	52	52	-	5	1.06	1.06	-	0.23
Technical revisions	444	323	121	560	(4.18)	(4.43)	250	0.31
Acquisitions	485	485	-	1,321	164.79	164.79	-	29.27
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	(13)	(7)	(6)	(18)	(1.62)	(1.62)	-	(0.30)
Production	(729)	(636)	(93)	(812)	(60.18)	(60.00)	(181)	(11.57)
Closing Balance	4,070	3,549	521	7,302	541.35	540.12	1,231	101.60
<b>PROBABLE</b>								
Opening Balance	1,219	989	230	1,908	142.96	142.69	274	26.96
Exploration discoveries	-	-	-	-	-	-	-	-
Drilling extensions and improved recovery	26	26	-	1,206	117.41	117.41	-	20.80
Infill Drilling	16	16	-	2	.06	.06	-	0.03
Technical revisions	(237)	(134)	(103)	(95)	(19.26)	(19.27)	9	(3.54)
Acquisitions	149	149	-	413	47.07	47.07	-	8.41
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	(6)	(1)	(5)	-	0.12	0.12	-	0.01
Production	-	-	-	-	-	-	-	-
Closing Balance	1,168	1,046	122	3,435	288.36	288.07	283	52.66
<b>PROVED PLUS PROBABLE</b>								
Opening Balance	4,983	4,254	729	6,598	461.95	460.52	1,436	88.57
Exploration discoveries	-	-	-	-	-	-	-	-
Drilling extensions and improved recovery	95	95	-	2,762	239.90	239.90	-	42.84
Infill Drilling	68	68	-	7	1.12	1.12	-	0.26
Technical revisions	207	189	18	466	(23.44)	(23.07)	260	(3.24)
Acquisitions	634	634	-	1,735	211.86	211.86	-	37.68
Dispositions	-	-	-	-	-	-	-	-
Economic Factors	(19)	(8)	(11)	(18)	(1.50)	(1.50)	-	(0.29)
Production	(729)	(636)	(93)	(812)	(60.18)	(60.00)	(181)	(11.57)
Closing Balance	5,238	4,595	643	10,737	829.71	828.19	1,514	154.26

## Reserve Additions and Revisions

Reserve additions were almost entirely the result of two factors. The first was the completion of the Arrangement on January 15, 2009. The second was drilling extensions, scattered throughout the Company's major properties but with the Town and Gold Creek areas being the biggest contributors. Technical revisions were slightly positive for proved reserves, at 0.1%, and slightly negative for proven plus probable reserves, at -3.8%. They were generally the result of poorer than expected performance, especially on wells that had little or no production history available when last evaluated.

## Additional Information Relating to Reserve Data

### Undeveloped Reserves

#### *Proved Undeveloped Reserves*

Most of the Company's proved undeveloped reserves fall within the following categories:

- Wells expected to be drilled in within the next 2 years;
- Gas caps that will be blown down once the oil has been depleted; and
- Secondary zones that will be brought on production once the primary zone has been depleted.

The Company does not carry proved undeveloped reserves for long periods of time unless there is a good reason (such as the above) for not putting these reserves on production in the short term. In fact, where there is sufficient economic justification, the Company will often take steps to accelerate production from gas caps and secondary zones. These steps involve early gas cap blow down when it does not significantly impact oil recovery and dually completing or twinning wells for secondary zones.

**Gross Reserves First Attributed by Year <sup>(1)</sup>**

	<b>Light &amp; Medium Oil (Mbbbl)</b>	<b>Natural Gas (MMcf)</b>	<b>Natural Gas Liquids (Mbbbl)</b>	<b>Coal Bed Methane (MMcf)</b>	<b>MBOE</b>
	<b>First Attributed</b>	<b>First Attributed</b>	<b>First Attributed</b>	<b>First Attributed</b>	<b>First Attributed</b>
Prior	84	11,390	109	-	2,091
2007	69	22,479	296	193	4,144
2008	122	35,578	310	117	6,382
2009	57	57,851	861	-	10,561

Note:

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

#### *Probable Undeveloped Reserves*

Thirty eight percent of the Company's probable reserves are attributed to more optimistic recoveries from producing wells. The remaining probable reserves for the most part are attributed to infill and step-out drilling locations, re-completions, and tie-ins that are anticipated to proceed within a reasonable time frame but do not meet the required confidence factor to be booked as proved. The comments above regarding the Company's efforts to put proved undeveloped reserves onstream also apply to probable.

**Gross Reserves First Attributed by Year <sup>(1)</sup>**

	<b>Light &amp; Medium Oil (Mbbbl)</b>	<b>Natural Gas (MMcf)</b>	<b>Natural Gas Liquids (Mbbbl)</b>	<b>Coal Bed Methane (MMcf)</b>	<b>MBOE</b>
	<b>First Attributed<sup>1</sup></b>	<b>First Attributed</b>	<b>First Attributed</b>	<b>First Attributed</b>	<b>First Attributed</b>
Prior	37	12,464	115	-	2,230
2007	36	21,169	268	49	3,841
2008	52	32,261	265	22	5,698
2009	19	89,338	998	-	15,906

Note:

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

**Significant Factors or Uncertainties**

Estimates of economically recoverable oil and natural gas reserves (including natural gas liquids) and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from actual results. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Company's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

The Company's independent engineering firm, GLJ, uses a deterministic approach in the estimation of reserves. Reserves are assessed using a discrete value for each parameter in the calculation of reserves, such that the resultant reserve value is consistent with the certainty level associated with the reserve classification. In accordance with NI 51-101, the following definitions are followed by GLJ in their analysis:

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

**Future Development Costs**

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

<b>(\$ millions)</b>	<b>Forecast Prices and Costs</b>	
	<b>Proved Reserves</b>	<b>Proved Plus Probable Reserves</b>
<b>Year</b>		
2010	93,073	123,322
2011	87,853	172,056
2012	47,670	91,043
2013	38,138	50,745
2014	18,748	23,040
<b>Total</b>	<b>318,676</b>	<b>510,457</b>

In all years of the economic forecasts, the net revenues from the Company's reserves are well in excess of the estimated future development costs. The future development costs scheduled for 2010 of \$93 million on total proved reserves and \$123 million on proved plus probable reserves represent 27 percent and 35 percent of the 2010 capital budget, respectively. The Company expects to fund these expenditures using cash flow from operations and no other source of funding is required to develop the proved or the proved plus probable reserves, however, should

the need arise, the Company has available amounts on its credit facility on which it can draw funds or the ability to issue equity if available and on favourable terms. At December 31, 2009 the Company had a \$650 million Credit Facility and bank debt of \$277.9 million. Any costs that may be associated with funding these expenditures would not affect the reserves at all and would not be material in comparison with the future net revenue.

### **Other Oil and Gas Information**

Progress' core operations are in the Foothills region of northeast British Columbia and the Deep Basin Region of northwest Alberta. The Company also operates in the Fort St. John Plains region of northeast British Columbia and central Alberta along with other operations in both provinces. The core regions provide multi-zone production opportunities and year round access with existing gathering and processing facilities. The Company's growth has been derived primarily from the Foothills and Deep Basin regions and the 2010 capital program will primarily be directed to these regions. The Company is the operator of the majority of its properties and has contiguous undeveloped acreage in its regions of operations.

The Company has developed a substantial land and production base in the Deep Basin of northwest Alberta and the Foothills of northeast British Columbia. Progress has been an active driller and land acquirer in these regions and has a strong understanding of government, environment and First Nations issues, which may be barriers to entry for many of its competitors. Prior to the Arrangement, the Trust entered the Deep Basin region in July 2004 and has since that time steadily grown production through drilling and select acquisitions. Progress has also grown its position in the northeast British Columbia Foothills region since 2002 when it started with the acquisition of three producing wells in the Town and Beg areas.

#### **British Columbia**

***Foothills*** Approximately 100 kilometres northwest of the city of Fort St. John, British Columbia is the Foothills region which is a key region of focus for the Company. The region has historically been explored for and developed in the same formations as those found on the Fort St. John block (Cretaceous and Triassic sands) but are thicker and fractured on a series of parallel anticlines giving rise to larger accumulations with high flow rates. The primary target Halfway zone is a tight but thick gas charged reservoir approximately 100 to 150 feet thick, where folded and fractured by mountain building compressive forces from the west. The Halfway formation, together with other natural gas zones stacked above, can produce commercial, long life, gas flow rates. The Company has been able to successfully image and identify these features using modern 3-D seismic data. In addition, the Company has recently had success exploring and exploiting shallower targets in the Bluesky-Gething interval and has also been exploring in the deeper Mississippian Debolt formation.

In 2009 the Company began to focus on the Montney formation in the Foothills region. The Montney is a thick shale formation that is pervasive over a large areal extent in northeast British Columbia. A successful vertical and horizontal well program in the Town area resulted in the commencement of phase one of the Company's Montney development program in 2010. The Company continues to have an active grassroots vertical and recompletion program to expand the known productive areas in the Montney formation on the Company's land base. Progress currently holds over 680,000 net acres of land with Montney rights in the Foothills region.

In 2010, Management estimates 60 percent of its capital spending will be directed in the Foothills region, primarily focused on the Montney formation.

***Fort St. John Plains*** The Fort St. John Plains region is located in close proximity to the city of Fort St. John, British Columbia on the northern flank of the Peace River. This region produces light oil and natural gas from a predictable sequence of porous Cretaceous sands and Triassic aged sandstones and carbonates. Up to ten separate and distinct reservoirs can be encountered in a typical 1,200 metre depth well in the Fort St. John Plains exploration region.

***Deep Basin - Ojay*** The Ojay property is on trend into British Columbia to the north and west of the Copton/Lynx property in the Foothills of Alberta. The production from this region is primarily from the Cadotte and Falher formations. More recently, industry has been actively exploring the Nikanassin formation in this area. Management

is of the view that upside potential in the region exists in the untested fault blocks visible on existing 3D data controlled by the Company.

### *Alberta*

**Deep Basin** The Company's main interests in the Deep Basin are located immediately south of the city of Grande Prairie. The region includes its primary producing areas at Gold Creek, Karr Elsworth and Wapiti areas. This region is characterized by multi-zone, liquids-rich gas and light oil productive horizons with up to 14 producing horizons in the Cretaceous and Triassic sections found at depths from 1,300 to 2,600 meters. Many of the formations require stimulation in order to produce. Target zones in the region include significant reserves within the, Halfway, Charlie Lake, Bullhead, Fort St. John, Dunvegan, Nikanassin, Gething and Bluesky formations. The area has very well developed infrastructure and the Company has a 27 percent interest in the Gold Creek gas plant, which currently has a licensed processing capacity of 120 mmcf/d of natural gas. Additionally, the Company has smaller working interests in the Karr and Wapiti gas plants. Sufficient takeaway capacity exists on the NOVA and Alliance systems. Just to the south of Gold Creek is the Copton / Lynx property. The production from Copton / Lynx is 100 percent natural gas and is currently producing primarily from the Cadotte and Cardium formations. Management estimates 40 percent of its capital spending will be directed in the Deep Basin region.

**Central Alberta** The Central Alberta region consists of lands primarily west of the city of Red Deer, Alberta between Sylvan Lake and Gull Lake. Gas production in this region is commonly obtained from the Pekisko, Mannville and Edmonton Sands formations.

The following table indicates the average daily production by operating regions for 2009:

<b>Region</b>	<b>Light and Medium Oil (bbl/d)</b>	<b>Associated And Non-Associated Gas (Mcf/d)</b>	<b>Natural Gas Liquids (bbl/d)</b>	<b>BOE (BOE/d)</b>
Foothills	313	87,892	406	15,368
Fort St. John Plains	676	7,780	63	2,036
Other	-	4,416	-	736
<b>Total British Columbia</b>	<b>989</b>	<b>100,088</b>	<b>469</b>	<b>18,140</b>
Deep Basin	572	58,484	1,605	11,924
Central Alberta	201	6,688	198	1,514
Other	246	1,679	12	537
<b>Total Alberta</b>	<b>1,019</b>	<b>66,851</b>	<b>1,815</b>	<b>13,975</b>
<b>Total daily production</b>	<b>2,008</b>	<b>166,939</b>	<b>2,284</b>	<b>32,115</b>

### **Oil and Natural Gas Wells**

The following table sets forth the Company's gross and net interest in oil and natural gas wells which are producing and the number of non-producing wells and service wells as at December 31, 2009.

	<b>Producing Wells</b>				<b>Non-Producing Wells</b>				<b>Service Wells</b>	
	<b>Oil</b>		<b>Natural Gas</b>		<b>Oil</b>		<b>Natural Gas</b>		<b>Gross</b>	<b>Net</b>
	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>	<b>Gross</b>	<b>Net</b>		
British Columbia	45	31.9	391	323.3	28	16.1	206	158.7	12	8.9
Alberta	151	79.4	466	248.3	38	22.6	181	106.7	24	13.6
<b>Total</b>	<b>196</b>	<b>111.3</b>	<b>857</b>	<b>571.6</b>	<b>66</b>	<b>38.7</b>	<b>387</b>	<b>265.4</b>	<b>36</b>	<b>22.5</b>

### Properties with No Attributed Reserves

The following table sets forth the Company's undeveloped land holdings as at December 31, 2009.

	Undeveloped Acres	
	Gross	Net
British Columbia	942,000	806,000
Alberta	372,000	310,000
Total	1,314,000	1,116,000

Over the next 12 months approximately 176,000 net acres or 16 percent of the Company's undeveloped land will be subject to expiry. The Company has an active capital program to minimize undeveloped land expiries and programs to farm-out expiring lands which would not be continued in our core in non-core areas will be pursued.

### Additional Information Concerning Abandonment and Reclamation Costs

The Company estimates the costs associated with abandonment and reclamation costs for surface leases, wells and facilities through its previous experience, where available, or by estimating such costs. The Company expects to incur abandonment and reclamation costs on 1,542 gross wells (1,009.5 net wells) including currently producing, non-producing wells and service wells, detailed as follows:

(\$ millions)	Proved NPV 0%	Proved NPV 10%
Abandonment costs associated with wells that have assigned reserves	42	13
Reclamation costs associated with wells that have assigned reserves <sup>(1)</sup>	24	7
Abandonment and reclamation costs associated with non-producing, shut-in and wells that have no reserves assigned <sup>(1)</sup>	22	7
Total abandonment and reclamation cost provision	88	27
Portion forecast to be paid during the next three years	4	4

Note:

- (1) The Company has taken abandonment costs from the GLJ Progress Report (proved forecast) for wells that have reserves. Internal estimates were used for abandonment costs for wells that do not have reserves and surface reclamation costs for all wells. The internal estimates have not been deducted in estimating the future net revenue.

### Tax Horizon

The incomes taxes deducted in the calculation of future net revenue above assumes a blow down scenario whereby the Company produces out its existing reserves.

The Company forecasts its tax horizon, assuming current commodity prices, and a continuing business model whereby it reinvests capital at historic capital efficiencies and incurs general and administrative costs and interest costs. Under this scenario the Company does not forecast being in a taxable position for the next five years.

### Costs Incurred

During 2009 the Company incurred the following costs:

(\$ millions)	2009
Property Acquisition Costs – Unproved Properties <sup>(1)</sup>	30
Property Acquisition Costs – Proved Properties <sup>(1)</sup>	(2)
Exploration Costs	40
Development Costs	122

Note:

- (1) Property acquisition costs are net of dispositions and transfer.

## Exploration and Development Activities

The following table sets forth the gross and net exploration and development wells in which the Company participated during the year ended December 31, 2009:

	Development Wells		Exploration Wells		Total Wells	
	(gross)	(net)	(gross)	(net)	(gross)	(net)
Oil wells	-	-	-	-	-	-
Natural gas wells	34	27.0	14	13.1	48	40.1
Dry holes	-	-	4	4.0	4	4.0
<b>Total</b>	<b>34</b>	<b>27.0</b>	<b>18</b>	<b>17.1</b>	<b>52</b>	<b>44.1</b>

The Company's capital program has been set at approximately \$350 million for 2010. The Company expects to invest \$125 million in the first quarter of 2010.

## 2010 Production Estimates

Gold Creek is the only property that accounts for more than 20 percent of the total forecast production in 2010 and is identified in the following table. The following table indicates the gross average daily production for 2010 by area which is reflected in the estimate of future net revenue disclosed in the forecast price tables above:

Area	Light and Medium	Heavy Oil	Associated And	Natural Gas	BOE
	Oil		Non-Associated	Liquids	
	(bbl/d)	(bbl/d)	Gas	(bbl/d)	(BOE/d)
Total Proved					
Gold Creek	369	0	46,407	1,538	9,641
Other	826	239	134,229	1,491	24,928
<b>Total Proved Daily Production</b>	<b>1,195</b>	<b>239</b>	<b>180,636</b>	<b>3,029</b>	<b>34,569</b>
Probable					
Gold Creek	7	0	1,663	70	355
Other	14	5	8,345	65	1,475
<b>Total Probable Daily Production</b>	<b>21</b>	<b>5</b>	<b>10,007</b>	<b>136</b>	<b>1,830</b>

## Production History

Progress' approximate net daily production, before deduction of royalties, for the periods indicated are summarized below.

	2009				
	Annual	Q4	Q3	Q2	Q1
Natural gas (Mcf/d)	166,939	161,497	157,522	174,472	174,535
Light and medium oil (bbl/d)	2,008	1,882	1,874	2,121	2,151
Natural gas liquids (bbl/d)	2,284	2,592	1,995	2,617	1,930
<b>Total production (BOE/d)</b>	<b>32,115</b>	<b>31,390</b>	<b>30,122</b>	<b>33,817</b>	<b>33,170</b>

The following table indicates the average daily production for areas which comprise more than 20 percent of the Company's total production for 2009:

Area	Light and Medium Oil (bbl/d)	Associated And Non-Associated Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	BOE (BOE/d)
Gold Creek	459	35,108	661	6,971
Other	1,579	131,831	1,623	25,144
<b>Total Company Daily Production</b>	<b>2,008</b>	<b>166,939</b>	<b>2,284</b>	<b>32,115</b>

Although many wells produce both crude oil and natural gas, a well is categorized as a natural gas well or an oil well based upon the proportion of natural gas or crude oil production. The following table sets forth information with respect to average net product prices received, royalties paid, operating expenses and operating netbacks received by Progress in respect of Progress' production of crude oil, natural gas liquids and natural gas by quarter for 2009.

2009	Crude Oil				Natural Gas			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
	\$/bbl	\$/bbl	\$/bbl	\$/bbl	\$/Mcf	\$/Mcf	\$/Mcf	\$/Mcf
Average Price Received	41.85	47.03	53.87	57.03	5.64	3.90	3.45	4.65
Realized gain on financial instruments	-	-	-	-	1.05	-	0.07	(0.01)
Royalties	(9.04)	(8.15)	(9.61)	(13.12)	(0.88)	(0.32)	(0.26)	(0.59)
Operating expenses	(13.42)	(15.19)	(14.19)	(14.73)	(1.03)	(1.08)	(1.05)	(0.98)
Transportation expenses	(1.95)	(1.84)	(1.69)	(1.81)	(0.49)	(0.50)	(0.57)	(0.55)
<b>Netback Received</b>	<b>17.44</b>	<b>21.85</b>	<b>28.38</b>	<b>27.37</b>	<b>4.29</b>	<b>2.00</b>	<b>1.64</b>	<b>2.52</b>

2009	Average Selling Price			
	Q1	Q2	Q3	Q4
Light and medium crude (\$/bbl)	44.50	56.15	69.66	71.06
Natural gas liquids (\$/bbl)	38.98	37.61	41.46	49.15
Natural gas (\$/Mcf)	5.52	3.62	3.10	4.21

### Marketing Arrangements

Wherever possible, the Company has arranged to take-in-kind its share of crude oil, natural gas, and natural gas liquids on non-operated properties. Bids are requested in order to obtain the most advantageous price for crude oil and natural gas liquids sales. In situations where the volumes are small on non-operated properties, the property operator handles marketing activities.

At December 31, 2009, approximately 98 percent of our natural gas production was internally marketed. Additionally, approximately 98 percent of crude oil and 95 percent of natural gas liquids production was internally marketed and sold at market prices selected through a bid process. Competitive market prices are received for product sales through the use of numerous investment grade and secure counterparties selected in accordance with our corporate credit policy.

The Company contracts for firm transportation on the TransCanada and ATCO systems in Alberta and the Spectra Energy Corp. system in British Columbia. The contracts expire at various times over the next five years. The table below details the financial commitments of the transportation contracts:

<i>(\$ thousands)</i>	<b>Total</b>	<b>Minimum Annual Commitment</b>				
		<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>	<b>2014</b>
Pipeline commitments	66,722	34,343	24,416	5,227	2,028	708

The Company has entered into certain derivative financial instruments under its commodity risk management program to hedge its exposure to natural gas prices. The terms and commitments of these instruments are disclosed in note 12 to the consolidated financial statements for the year ended December 31, 2009.

## APPENDIX B

### PROGRESS ENERGY RESOURCES CORP. MANDATE & TERMS OF REFERENCE OF THE AUDIT COMMITTEE

#### Role and Objective

The Audit Committee (the "Committee") is a committee of the board of directors of Progress Energy Resources Corp. ("Progress") to which the board has delegated its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for board of director approval, the audited financial statements and other disclosure releases containing financial information, and review of the annual reserves. The objectives of the Committee are as follows:

1. To assist directors in fulfilling their legal and fiduciary obligations (especially for accountability) in respect of the preparation and disclosure of the financial statements of Progress and related matters;
2. To oversee the audit efforts of the external auditors of Progress ;
3. To maintain free and open means of communication among the directors, the external auditors, the financial and senior management of Progress;
4. To satisfy itself that the external auditors are independent of Progress;
5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors;
6. The Audit Committee shall, in the exercise of its powers, authorities and discretion so authorized, conform to any regulations or restrictions that may from time to time be made or imposed upon it by the Board of Directors or the legislation, policy or regulation governing the Company and its business.

The function of the Committee is oversight. Management is responsible for the preparation, presentation and integrity of the financial statements of Progress and is responsible for maintaining appropriate accounting and financial reporting principles and policy and internal controls and procedures that provide for compliance with accounting standards and applicable laws and regulations. The external auditors are responsible for planning and carrying out a proper audit of the annual financial statements of Progress, reviews of the annual and quarterly financial statements of Progress prior to their filing with securities regulatory authorities and other procedures. In fulfilling their responsibilities and duties, it is recognized that Members of the Committee are not full-time employees of Progress and are not, and do not represent themselves to be, accountants or auditors by profession or experts in the fields of accounting or auditing including in respect of auditor independence. As such, it is not the duty or responsibility of the Committee or its Members to plan or conduct the audit or to determine whether the financial statements of Progress are complete and accurate and are in accordance with generally accepted accounting principles.

#### Composition of Committee

1. The Committee shall be comprised of at least three (3) directors of Progress, none of whom are members of management of Progress and all of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110")).
2. The Board of Directors shall have the power to appoint the Committee Chairman, who shall be an unrelated director.

3. All of the members of the Committee shall be "financially literate" as defined in NI 52-110. The Board of Directors of Progress has adopted the definition for "financial literacy" and the definition of "audit committee financial expert" used in MI 52-110.
4. Unless otherwise ordered by the Board of Directors, each member of the Audit Committee shall continue to be a member thereof until the expiration of his term of offices as director;
5. The Board of Directors may from time to time modify, dissolve or reconstitute the Audit Committee and may make such regulations with respect to and impose such restrictions upon the exercise of the power, authorities and discretion of the Audit Committee as the Board of Directors considers expedient;
6. The members of the Audit Committee as such shall be entitled to such remuneration for their services as Chairman and members of the Audit Committee as may be fixed by the Board of Directors.

#### Meetings

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall not be entitled to a second or casting vote.
2. A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the board.
3. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken.
4. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the board.
5. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year end financial statements) and at such other times as the external auditor and the Committee consider appropriate.
6. The Committee shall meet with the external reserve evaluators or the reserves committee of the Board of Directors, if one is appointed, at least once per year (in connection with the preparation of the year end reserves).
7. The Audit Committee may invite such directors, officers and employees of the Company and the external auditors of the Company as it may see fit to attend its meetings and to take part in the discussion and consideration of the affairs of the Audit Committee;
8. The meetings of the Audit Committee shall be convened at the direction of any member thereof or the Chairman, President or Vice President, Finance of the Company, the Board of Directors or the external auditors.
9. No business shall be transacted by the Audit Committee except at a meeting of its members at which a quorum is present in person or by telephone or by a resolution in writing signed by all of the members of the Audit Committee; and
10. The meetings and proceedings of the Audit Committee shall be governed by the provisions of the by-laws of the Company that regulate meetings and proceedings of the Board of Directors insofar as the same are applicable thereto and are not superseded by any regulations or restrictions made or imposed by the Board of Directors, and provided that it is confirmed that the Chairman of the Audit Committee shall not have a second or casting vote.

**Mandate and Responsibilities of Committee**

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting. The external auditors shall report directly to the Committee.
2. It is the responsibility of the Committee to satisfy itself on behalf of the board with respect to Progress' Internal Control Systems:
  - identifying, monitoring and mitigating business risks; and
  - ensuring compliance with legal, ethical and regulatory requirements.
3. It is a primary responsibility of the Committee to review the annual financial statements of Progress prior to their submission to the board of directors for approval. The process should include but not be limited to:
  - Reviewing and accept, if appropriate, the annual audit plan of the external auditors of Progress, including the scope of audit activities, and monitor such plan's progress and results during the year;
  - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
  - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
  - reviewing the methods used to account for significant unusual or non-recurring transactions;
  - ascertaining compliance with covenants under loan agreements;
  - reviewing disclosure requirements for commitments and contingencies;
  - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
  - reviewing unresolved differences between management and the external auditors;
  - obtain explanations of significant variances with comparative reporting periods;
  - review of business systems changes and implications;
  - review of authority and approval limits;
  - review the adequacy and effectiveness of the accounting and internal control policies of Progress and procedures through inquiry and discussions with the external auditors and management;
  - confirm through private discussion with the external auditors and the management that no management restrictions are being placed on the scope of the external auditors' work;
  - review of tax policy issues; and
  - review of emerging accounting issues that could have an impact on Progress.
4. The Committee is to review the financial statements (and make a recommendation to the board of directors with respect to their approval), interim financial statements, prospectuses, management discussion and

analysis (MD&A), annual information forms (AIF) and all public disclosure containing audited or unaudited financial information before release and prior to board approval. The Committee must be satisfied that adequate procedures are in place for the review of Progress' disclosure of all other financial information and shall periodically access the accuracy of those procedures.

5. With respect to the appointment of external auditors by the board, the Committee shall:
  - recommend to the board the appointment of the external auditors;
  - review the performance of the external auditors and make recommendations to the directors regarding the replacement or termination of the external auditors when circumstances warrant;
  - oversee the independence of the external auditors by among other things; requiring the external auditors to deliver to the Committee on a periodic basis a formal written statement delineating all relationships between the external auditors and Progress and its subsidiaries;
  - recommend to the board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee; and
  - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
6. Review with external auditors (and internal auditor if one is appointed by Progress) their assessment of the internal controls of Progress, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Progress and its subsidiaries.
7. The Committee must pre-approve all non-audit services to be provided to Progress or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.
8. The Committee shall review risk management policies and procedures of Progress (i.e. hedging, litigation and insurance), including the annual review of insurance coverage.
9. The Committee shall establish a procedure for:
  - the receipt, retention and treatment of complaints received by Progress regarding accounting, internal accounting controls or auditing matters; and
  - the confidential, anonymous submission by employees of Progress of concerns regarding questionable accounting or auditing matters.
10. The Committee shall review and approve Progress' hiring policies regarding employees and former employees of the present and former external auditors of Progress.
11. The Committee shall have the authority to investigate any financial activity of Progress. All employees of Progress are to cooperate as requested by the Committee.
12. The Committee may retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at the expense of Progress without any further approval of the board.

13. The responsibilities, practices and duties outlined herein are not intended to be comprehensive. The Board of Directors shall consider from time to time any additional areas, which may require review when determining the responsibilities, practices and duties to be assigned to the Audit Committee.
14. It is confirmed that the Audit Committee shall periodically report the results of reviews undertaken and any associated recommendations to the Board of Directors.