

PROGRESS ENERGY RESOURCES CORP.

Annual Information Form

For the year ended December 31, 2010

March 11, 2011



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SELECTED DEFINITIONS

In this Annual Information Form, the following abbreviations and terms have the meanings set forth below, 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 Canadian Securities Administrators Staff Notice 51-324 - *Glossary To NI 51-101 Standards of Disclosure For Oil And Gas Activities*;

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

"**DRIP**" means the dividend reinvestment plan of Progress whereby Shareholders can elect to reinvest their dividends in Shares.

"**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, which were assumed by the Company from the Trust on January 15, 2009 in connection with the Arrangement and which matured on June 30, 2010;

"**Fourth Debentures**" means the 5.75% convertible unsecured subordinated debentures due June 30, 2016, which were issued by the Company on March 7, 2011;

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

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

"**GLJ Progress Report**" means the report prepared by GLJ dated February 8, 2011 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, 2010;

"**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 Company and Progress Energy Ltd.;

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

"**Private Subscription Receipt Agreement**" means the agreement dated March 2, 2010 between the Company, CPPIB and the Escrow Agent governing the terms of the subscription receipts of the Company;

"**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 Company, the Underwriters and the Escrow Agent governing the terms of the issuance of subscription receipts of the Company;

"**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", in this Annual Information Form, unless the context otherwise requires, are references to Progress Energy Trust, its predecessors and its subsidiaries;

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

"**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.

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.
BOE/d	Barrel of oil equivalent per day
GJ	Gigajoule
m ³	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

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, 2010. Totals may not add due to rounding.

**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, 2010 and the reserves information contained in the Annual Information Form has been prepared as of February 8, 2011.

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.

Additional clarification of certainty levels associated with reserve estimates and the effect of aggregation is provided in Section 5 of the COGE Handbook.

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.

"Exploratory 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 its 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 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;
- the Company's plans to fund future development costs;
- timing of development of undeveloped reserves;
- estimated working interest;
- tax horizon;
- capital spending to be directed to the Deep Basin region and Montney region;
- expected abandonment and reclamation costs;
- geologic and geographic expansion plans and the results therefrom;
- the Company's capital program;
- the Company's plans to dispose of assets, including the amount and expected timing thereof;
- the Company's evaluation of joint venture alternatives and the expected results thereon;
- 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, acquisition and divestiture 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;
- expected production from Montney pods in the Foothills region of northeast British Columbia;
- expected drilling activities as a result of the Company's capital program;
- 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 exploration and development program and other 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; and
- realization of the anticipated benefits of acquisitions 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, 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; and
- 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.

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 acquired assets into the Company's operations;
- 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 Annual Information Form 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".

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 – 5th Avenue S.W., Calgary, Alberta, T2P 2V7 and its registered office is located at Suite 1400, 350 – 7th 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.

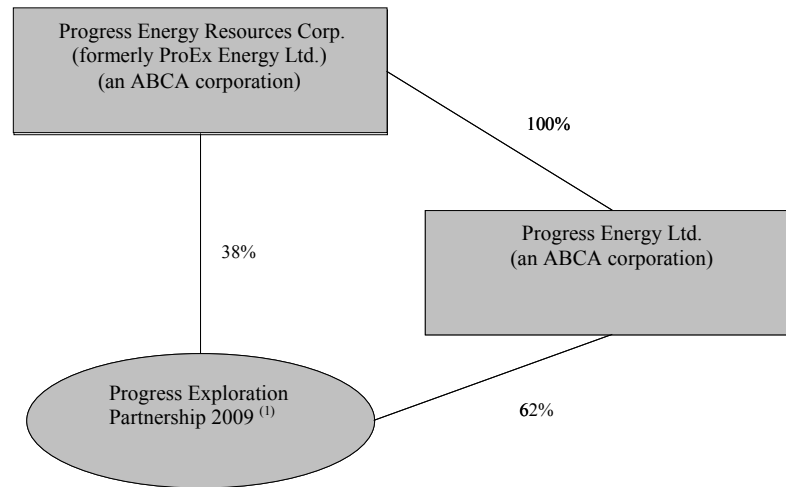
Inter-Corporate Relationships

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.

	<u>Percentage of voting securities (directly or indirectly)</u>	<u>Jurisdiction of Incorporation or Formation</u>
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. Progress' current exploration and development programs focus on opportunities in the Montney formation in the Foothills region of northeast British Columbia and the Nikanassin in the Deep Basin region of northwest Alberta. 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 may 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 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; it has 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 Company may also choose to dispose of non-core assets or pursue joint venture arrangements when it can be accomplished on economical terms acceptable to the Company.

The Shares trade on the TSX under the symbol PRQ. The Second Debentures, Third Debentures and Fourth Debentures trade on the TSX under the symbols PRQ.DB.A, PRQ.DB.B, and PRQ.DB.C, respectively. The First Debentures matured on June 30, 2010.

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 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 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. The First Debentures matured on June 30, 2010.

In accordance with GAAP, the Arrangement was accounted for as a reverse takeover, whereby the Trust was 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 Units 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.
- Increased the number of emergency response exercises conducted to further enhance our emergency preparedness.
- Initiated the implementation of a web based performance and compliance management tool to further improve our capture and follow-up on inspections, incidents, near misses and the various regulatory compliance requirements.
- Maintained an active site abandonment and reclamation program which has resulted in 25 reclamation certificates being received in 2010.

Progress continually works to improve its health and safety performance through increased awareness in the field by frequently communicating safety expectations and responsibilities to its employees and contractors, by issuing/sharing safety information and by the promotion of industry recognized best practices.

In 2010, Progress' overall health and safety performance continued to improve. There has been no employee lost time incidents in the last 3 years. Progress' contractors had two lost-time incidents in 2010 compared to four in 2009 and our Total Recordable Incident Frequency (TRIF) is 0.72 which is top quartile amongst our peers.

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. See "*Risk Factors*". 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 available on acceptable terms.

Personnel

As at December 31, 2010 Progress employed a total of 129 employees.

GENERAL DEVELOPMENT OF THE BUSINESS

Three Year Historical Overview

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 period from October 1, 2009 to December 31, 2009. Progress intends to continue to pay quarterly dividends, however these dividends are not guaranteed. See "*Risk Factors*".

2010

On March 31, 2010, the Company acquired certain northeast British Columbia Foothills assets for \$389.2 million, including \$2.1 million in transaction costs (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 represent 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.

To finance the Foothills Acquisition and a portion of the Company's 2010 capital program, the Company issued 47,630,000 Shares at a price of \$12.60 per Share for total gross proceeds of \$600.1 million (\$588.8 million net of issue costs of \$11.3 million). The Share issuance was comprised of a \$350 million subscription receipt private placement with the CPPIB (the "**Private Placement**") and a concurrent \$250 million subscription receipt public offering through a syndicate of underwriters. Each subscription receipt represented the right to receive one Share of Progress, without the payment of any additional consideration, on the closing of the Foothills Acquisition, which occurred on March 31, 2010. Pursuant to the Private Placement Agreement, CPPIB has agreed not to sell any of the Shares issued pursuant to the Private Placement for 18 months following the closing, unless otherwise approved by the Company.

In connection with the Private Placement, the Company entered into the Private Placement Agreement with the CPPIB pursuant to which the Company and CPPIB have agreed to certain matters in connection with the 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. CPPIB, having greater than 12.5% of the outstanding Shares, nominated R. Scott Lawrence, Vice President – Head of Relationship Investments, Public Market Investments of CPPIB to the Progress Board of Directors. The Progress Board of Directors, upon review of Mr. Lawrence's qualifications by the Corporate Governance and Nominating Committee, appointed Mr. Lawrence to the Board on October 12, 2010.

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 subscription receipts to CPPIB, 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.

On June 30, 2010 Progress disposed of its Central Alberta properties for approximately \$42.9 million.

During 2010, the Company carried out a \$375 million capital program, before acquisitions and dispositions. The focus of the program was to establish additional Montney commercial development pods throughout the Company's extensive Foothills acreage in northeast British Columbia and further de-risk the Company's lands. As a result, Progress identified six commercial development pods on its Montney land base in 2010 and a material successful step-out horizontal well in the Caribou area extended the Montney play 55 kilometers to the north of the Company's Town South development. Progress expects that each pod can be developed to a 50 MMcf/d natural gas asset, with sufficient well inventory remaining to maintain that production level for 10 years.

During 2010, the Company declared quarterly dividends which totalled \$86.9 million or \$0.40 per Share for the year ended December 31, 2010. In 2010, 1,324,601 Shares were issued under the DRIP and on January 17, 2011 the Company issued 516,775 Shares in payment of \$6.3 million of dividends to Shareholders who elected to participate in the DRIP for the period from October 1, 2010 to December 31, 2010. Progress intends to continue 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.

RECENT DEVELOPMENTS

Share and Fourth Debenture Financing

On March 7, 2011, Progress issued 14,400,000 Shares at \$13.90 per Share for gross proceeds of \$200.2 million (which includes CPPIB's subscription noted below) and \$200 million principal amount of Fourth Debentures for total combined gross proceeds of \$400.2 million (\$385.3 million net of estimated issue costs). Each Fourth Debenture may be converted into Shares at the option of the holder at a conversion price of \$20.85 per Share. The Fourth Debentures pay interest semi-annually on June 30 and December 31 in each year commencing on June 30, 2011 and mature on June 30, 2016. The Company may satisfy the payment of principal and interest in Shares under certain circumstances. The net proceeds were initially used to reduce the Company's outstanding bank debt thereby freeing up borrowing capacity to fund a portion of the Company's \$350 million capital program for 2011 (see "*Outlook*" below).

Pursuant to its existing subscription right, CPPIB, which prior to completion of the offering owned approximately 14.7 percent of Progress' outstanding Shares, agreed to subscribe for 2,116,800 Shares at a price of \$13.90 per Share. See "*General Development of the Business – Three Year Historical Overview – 2010 – Subscription Rights*". CPPIB has agreed, in connection with its subscription for 2,116,800 Shares, not to sell, or agree to sell (or announce any intention to do so), or otherwise dispose of its economic interest in any Shares or securities exchangeable or convertible into Shares of the Company for a period of 90 days following the closing of the issuance of the 2,116,800 Shares without prior written consent of BMO Nesbitt Burns Inc. and Scotia Capital Inc., which consent may not be unreasonably withheld, or in certain circumstances relating to a proposed change of control transaction involving the Company. See "*Escrowed Securities*".

Oil and Gas Activities Update

General

Exit rate production for 2010 was approximately 45,000 BOE/d with fourth quarter production averaging approximately 42,700 BOE/d. Fourth quarter cash flow from operating activities (before changes in non-cash

working capital) was approximately \$59 million. Capital investment in 2010 was \$375 million, before acquisitions and divestitures, and year-end 2010 bank debt was approximately \$333 million including working capital.

The following are certain operational highlights:

- Progress is currently producing approximately 55 MMcf/d, net, from the Montney formation;
- since 2009, the Company has drilled 11 wells at Town South into the Upper Montney formation with an average net production of five MMcf/d per well;
- Progress' first Town South Lower Montney horizontal well, drilled in the fourth quarter of 2010, tested at over 8.5 MMcf/d with approximately 20 barrels per MMcf of natural gas liquids and is currently producing approximately 5.6 MMcf/d;
- a Lower Montney horizontal well at Kobes, in which Progress has a 30 percent working interest, that was drilled in the fourth quarter of 2010, produced at 11.2 MMcf/d over 30 days of production; and
- a vertical exploratory well at Kahta, northwest of Caribou, drilled in the fourth quarter of 2010, tested at over 750 Mcf/d.

Progress has advanced its development plans on six Montney pods in the Foothills region of northeast British Columbia, which Progress believes are each capable of reaching gross production of 50 MMcf/d and could sustain at that production level for approximately 10 years. Progress holds approximately 700,000 net acres of Montney rights in the Foothills region and approximately 900,000 net acres of Montney rights over its entire land base, making it one of the largest Montney land rights holders.

Town South Development Pod

The Company's most mature Montney development is at Town South where Progress drilled its first Montney well more than two years ago. Since that time, the Company has drilled 11 horizontal wells with average 30-day initial production rates of five MMcf/d. Additionally, the wells have averaged approximately 20 barrels per MMcf of high value natural gas liquids, enhancing the economics of this play in the current natural gas price environment.

In 2010, the Company constructed a compression and dehydration facility at Town South and has recently expanded the facility to handle 50 MMcf/d. The facility is currently handling in excess of 35 MMcf/d. Progress plans on drilling an additional four horizontal wells in the first quarter of 2011 and anticipates that its facility will be operating at near capacity by the end of the first quarter.

In the fourth quarter of 2010, Progress drilled its first lower Montney horizontal 100% test at Town South. This well tested with net production in excess of 8.5 MMcf/d, which Progress believes confirms the productive quality of the 200 meter thick Lower Montney interval. In addition, the well produced natural gas liquids consistent with previously drilled wells in the Upper Montney.

Kobes Development Pod

Activities completed in the fourth quarter of 2010 at its Kobes development pod in the North Montney region, where the Company holds a 30 percent working interest, include a fourth horizontal well that was recently completed. This well had a one month production rate over 11 MMcf/d and is located approximately six kilometers north of the first horizontal well at Kobes which produced at an average rate of 7.7 MMcf/d on a first month test.

In the fourth quarter of 2010, Progress initiated exploration of the Upper Montney zone at Kobes. The first horizontal well drilled into the Upper Montney will be tied into Progress' gathering system. The last flow rate on the horizontal well in December of 2010 was 2.4 MMcf/d and the well is currently producing approximately 2.1 MMcf/d.

In addition, during the fourth quarter of 2010, Progress recently started up its 25 MMcf/d gas handling facility at Kobes. The facility is on-stream and producing over 22 MMcf/d, of which 18 MMcf/d is from the Montney formation. Including non-operated production, the Kobes development pod is currently producing 30 MMcf/d (net 9 MMcf/d to Progress) from five horizontal and two vertical wells.

Montney Delineation Activities

The Company recently completed three vertical exploration wells that are located more than nine kilometres away from existing successful wells. The wells tested over one MMcf/d on average over a five-day test period. In particular, one well at Kahta, located approximately 20 kilometers north of Caribou, tested at 750 Mcf/d.

Deep Basin Activities

Progress drilled five (4.5 net) wells in the Deep Basin during the fourth quarter of 2010. Progress' Deep Basin wells typically yield approximately 40 barrels per MMcf of natural gas liquids when processed through the Wapiti Deep Cut Plant, a facility in which Progress has an ownership interest. The Company plans on drilling 14 wells in the first quarter of 2011 to take advantage of a \$200 per meter drilling credit before the program ends in April 2011. Progress has three drilling rigs currently operating in the Deep Basin.

Asset Dispositions/Joint Ventures

The Company is undertaking an asset disposition program representing less than 10 percent of the Company's production base or approximately 1,500 to 3,000 BOE/d which could be divested in 2011. The Company is also evaluating various joint venture alternatives on portions of its land base in the North Montney fairway. Discussions are ongoing with several parties in this regard, however, at this time no definitive agreements have been reached and there can be no assurance that any such agreements will be reached.

Dividends

On February 24, 2011, 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, 2011 to Shareholders of record as of March 31, 2011.

Potential Acquisitions

The Company continues to evaluate potential acquisitions of all types of petroleum and natural gas assets as part of its ongoing acquisition program. The Company is normally in the process of evaluating several potential acquisitions at any one time which individually or together could be material. As of the date hereof, the Company has not reached agreement on the price or terms of any potential material acquisitions. The Company cannot predict whether any current or future opportunities will result in one or more acquisitions for the Company.

Outlook

Along with the financing completed on March 7, 2011 (see "*Recent Developments*" above) Progress announced it was expanding its 2011 capital program from \$250 million to \$350 million. Under the expanded program the Company intends to accelerate the number of Montney wells to be drilled in 2011 to approximately 30 to 35 horizontal wells.

Based on the \$350 million capital program in 2011, Progress expects production to average approximately 45,000 to 46,000 BOE/d, which includes a scheduled plant turnaround at the third-party owned McMahon natural gas processing facility in northeast British Columbia in the second quarter that is forecasted to impact average annual production by approximately 1,200 BOE/d. Progress expects 2011 exit production to be 50,000 to 52,000 BOE/d, an increase of approximately 15 percent over 2010 exit production of approximately 45,000 BOE/d.

DESCRIPTION OF CAPITAL STRUCTURE

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 10, 2011, there were 229,846,561 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 the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB 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

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

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA prohibits discriminatory border restrictions and export taxes. NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

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

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

Alberta

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

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase

Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF ranged from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps were set at \$120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than \$535/m³ compared to the previous royalty curve.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF ranged from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps were set at \$16.59/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than \$5.25/GJ compared to the previous royalty curve.

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

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

In April 2005, the Government of Alberta implemented the Innovative Energy Technologies Program (the "IETP"), which has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP is backed by a \$200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a \$1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to \$3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of \$875,000 for wells exceeding 4,000 metres that are spud subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

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

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

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

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

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

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

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

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of \$3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the

vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

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

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

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

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to \$100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;
- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres spud between December 1, 2003 and September 1, 2009;
- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;
- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m³ of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;
- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m³ as well as a royalty credit for coalbed gas wells equal to \$50,000 for wells drilled on Crown land and a tax credit equal to \$30,000 for wells drilled on freehold land;
- *Marginal Royalty Reduction Program* providing royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m³ during the first 12 production months and average daily production less than 23 m³ for every metre of marginal well depth;
- *Ultra-Marginal Royalty Reduction Program* providing additional royalty 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 m³ during the first 12 production months and average daily production less

than 11.5 m³ (development wells) or 17 m³ (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 that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m³ of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In both 2009 and 2010, the Government of British Columbia allocated \$120 million in royalty credits for oil and gas companies under the Infrastructure Royalty Credit Program.

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

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta and British Columbia have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

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

notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

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

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

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

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

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

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

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO₂ equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO₂ equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at \$15 per tonne of CO₂ equivalent for the 2010 to 2012 period, rising to \$20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHGs. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

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

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

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

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 6 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark (the "**Copenhagen Conference**") resulted in the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. From November 29 to December 10, 2010, a meeting between representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

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

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

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

Alberta

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

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

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of \$15 per tonne of CO₂ equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

Progress does not own or have a working interest in any facility that exceeds the emissions threshold noted above.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at \$10 per tonne of CO₂ equivalent and rose to \$15 per tonne of CO₂ equivalent on July 1, 2009 and \$20 per tonne of CO₂ equivalent on July 1, 2010. It is scheduled to further increase at a rate of \$5 per tonne of CO₂ equivalent on July 1 of every year until it reaches \$30 per tonne of CO₂ 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 GHG emissions. It is expected that GHG emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO₂ 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 GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO₂ equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO₂ equivalents per year are required to have their emissions reports verified by a third party.

Progress has four facilities that emit over 10,000 tonnes of CO₂ equivalents per year and two that emit greater than 25,000 tonnes of CO₂ equivalents per year.

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 and in 2010, 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 30, 2011 (making the current maturity date March 30, 2012 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 2011 and there can be no assurance that the current borrowing base level of the Company will be maintained.

At January 31, 2011, approximately \$75.0 million aggregate principal amount of Second Debentures were outstanding and \$200.0 million aggregate principal amount of Third Debentures were outstanding. On March 7, 2011 the Company issued \$200 million aggregate principal amount of Fourth Debentures. The Second Debentures are due September 30, 2011, the Third Debentures are due October 31, 2014 and the Fourth Debentures are due on June 30, 2016. 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 greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. The Company will also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which are now expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gas 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

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.

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 under the symbol "PRQ". The following table sets forth the trading history of the Shares since January, 2010.

	Price Range		Volume
	High (\$)	Low (\$)	
2010			
January.....	14.70	13.27	10,410,622
February.....	14.14	12.13	18,240,451
March.....	13.83	11.25	20,519,504
April.....	12.97	11.65	18,526,979
May.....	12.35	10.67	17,185,278
June.....	14.37	11.93	23,252,175
July.....	12.95	12.00	7,259,307
August.....	12.58	10.86	15,405,155
September.....	12.25	11.02	19,731,571
October.....	12.00	10.30	13,677,039
November.....	12.29	10.85	16,449,280
December.....	13.15	11.00	11,040,350
2011			
January.....	14.10	11.88	15,302,206
February.....	14.84	12.77	18,056,576
March (to March 10).....	13.59	12.35	4,835,792

First Debentures

The First Debentures were settled on June 30, 2010. Prior to their settlement the trading history of the First Debentures since January 2010, under the symbol "PRQ.DB" on the TSX, was as follows.

	Price Range		Volume
	High (\$)	Low (\$)	
2010			
January.....	102.10	101.00	17,590
February.....	101.74	101.25	18,760
March.....	101.70	101.00	9,880
April.....	101.25	100.00	18,910
May.....	100.65	100.30	41,320
June.....	100.60	100.00	4,790

Second Debentures

The Second Debentures are listed and trade on the TSX. The current trading symbol for the Second Debentures is "PRQ.DB.A".

The following table sets forth the trading history of the Second Debentures since January 2010.

	Price Range		Volume
	High (\$)	Low (\$)	
2010			
January	102.75	101.00	2,320
February	103.01	101.80	4,250
March	104.50	102.25	12,880
April	102.99	101.89	4,440
May	102.49	101.55	7,250
June	103.00	101.81	3,200
July	102.99	102.30	5,290
August	103.00	102.31	19,890
September	102.60	102.25	8,870
October	102.25	101.05	6,920
November	102.00	100.75	14,410
December	102.01	100.80	3,240
2011			
January	102.00	101.30	4,830
February	102.00	101.32	8,120
March (to March 10)	102.50	101.60	4,360

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 January 2010.

	Price Range		Volume
	High (\$)	Low (\$)	
2010			
January	104.70	101.00	210,490
February	103.25	100.00	291,630
March	102.50	98.50	145,330
April	101.50	98.00	71,240
May	100.00	95.00	99,800
June	105.00	99.50	83,840
July	101.93	99.00	27,835
August	102.50	98.99	118,240
September	102.00	100.80	126,680
October	101.45	99.76	129,460
November	101.30	99.90	53,050
December	101.80	100.10	64,870
2011			
January	103.85	100.80	61,320
February	107.41	103.00	102,570
March (to March 10)	104.00	102.25	9,040

Fourth Debentures

The Fourth Debentures commenced trading on the TSX on March 8, 2011. The trading symbol for the Fourth Debentures is "PRQ.DB.C".

The following table sets forth the trading history of the Fourth Debentures since March 8, 2011.

	Price Range		Volume
	High (\$)	Low (\$)	
2011			
March (to March 10)	101.5	100.25	193,010

PRIOR SALES

On March 2, 2010, the Company issued 47,630,000 subscription receipts at a price of \$12.60 per subscription receipt pursuant to the Private Subscription Receipt Agreement and the Public Subscription Receipt Agreement. See "*General Development of the Business*".

DIVIDEND POLICY

Following the completion of the Arrangement, the Company established a dividend policy of paying quarterly dividends to Shareholders. Since March 31, 2009 the Company has declared quarterly dividends of \$0.10 per Share for each quarter throughout 2009 and 2010. During 2009, Progress established the DRIP whereby Shareholders can elect to receive their dividends in Shares.

2010

During 2010 Progress declared quarterly dividends of \$0.10 per Share to Shareholders of record on March 31, 2010, June 30, 2010, September 30, 2010 and December 31, 2010. The payment dates of the dividends were 15 days following the record date being April 15, 2010, July 15, 2010, October 15, 2010 and January 17, 2011. Subsequent to year end the Board of Directors declared that the 2011 first quarter dividend will be maintained at \$0.10 per Share. The dividend will be payable on April 15, 2011 to Shareholders of record as of March 31, 2011.

2009

During 2009 the Company declared quarterly dividends of \$0.10 per Share to Shareholders of record on March 31, 2009, June 30, 2009, September 30, 2009 and December 31, 2009. The payment dates of the dividends were 15 days following the record date being April 15, 2009, July 15, 2009, October 15, 2009 and January 15, 2010, respectively.

2008

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.

During 2008, the Trust paid cash distributions of \$0.10 per Unit on a monthly basis from January 2008 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 and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. See "*Risk Factors*".

The payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, the Company must be able to pay its liabilities as they become due and the realizable value of the Company's assets must be greater than its liabilities and the legal stated capital of the Company's outstanding securities. Unless otherwise indicated, all dividends paid or to be paid on the Shares are designated as "eligible dividends" for Canadian income tax purposes.

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, 2011.

Name	Principal Residence	Position Presently Held	Principal Occupation	Director⁽⁶⁾ or Officer Since
David D. Johnson	Alberta, Canada	Chairman and Director	Chairman, Progress	July, 2004
Michael R. Culbert ⁽⁵⁾	Alberta, Canada	President, CEO and Director	President & CEO, Progress	January, 2009
Donald F. Archibald ⁽¹⁾⁽⁴⁾	Alberta, Canada	Director	President, Cypress Energy Corp. (a private investment corporation)	January, 2009
John A. Brussa ⁽³⁾⁽⁴⁾	Alberta, Canada	Director	Partner of Burnet, Duckworth & Palmer LLP	January, 2009
Howard J. Crone ⁽¹⁾⁽²⁾	Alberta, Canada	Director	Executive Vice President & COO, Cequence Energy Ltd.	January, 2009
Greg W. Kist ⁽⁵⁾	Alberta, Canada	Vice President, Investor Relations and Marketing	Vice President, Investor Relations and Marketing, Progress	January, 2009
R. Scott Lawrence ⁽¹⁾	Ontario, Canada	Director	Vice President – Head of Relationship Investments, Public Market Investments, Canada Pension Plan Investment Board	October 2010
Art A. MacNichol ⁽⁵⁾	Alberta, Canada	Vice President, Finance & Chief Financial Officer	Vice President, Finance & Chief Financial Officer, Progress	January, 2009
Brian A. McLachlan ⁽²⁾⁽³⁾	Alberta, Canada	Director	President & CEO, Yoho Resources Inc.	July, 2004
Gary A. Miller ⁽⁵⁾	Alberta, Canada	Vice President, Operations	Vice President, Operations, Progress	January, 2009
Gary E. Perron ⁽¹⁾⁽³⁾	Alberta, Canada	Director	Managing Director and Senior Vice President BMO Nesbitt Burns	July, 2004
Cindy R. Rutherford ⁽⁵⁾	Alberta, Canada	Vice President, Land	Vice President, Land, Progress	January, 2009

Name Principal Residence	Position Presently Held	Principal Occupation	Director⁽⁶⁾ or Officer Since
James L. Stannard ⁽⁵⁾ Alberta, Canada	Vice President, Engineering	Vice President, Engineering, Progress	January, 2009
Terrance D. Svarich ⁽²⁾⁽⁴⁾ Alberta, Canada	Director	President, Devsun Ltd. (a private investment company)	July, 2004
Daniel C. Topolinsky ⁽⁵⁾ Alberta, Canada	Executive Vice President, Exploration and Development	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
- (6) Directors of the Company hold office until the next annual election of directors or until their successors are duly elected or appointed pursuant to the ABCA.

As at February 28, 2011 the directors and executive officers of Progress, as a group, beneficially owned or controlled or directed, directly or indirectly, 47,558,659 Shares or approximately 22 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 May 11, 2011 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.

Mr. David D. Johnson, has been our Chairman since February 2011 and prior to that he was our Executive Chairman from January, 2009. Prior to this he was our President and Chief Executive Officer from July 2004 to January 2009.

Mr. R. Scott Lawrence, 37, is Vice President, Head of Relationship Investments for CPPIB since March 2009. Prior to this he was Senior Principal, Private Investment, and Infrastructure for CPPIB from September 2005 to February 2009. Prior thereto Mr. Lawrence was a Senior Associate for Onex Corporation from June 2001 to May 2004. Mr. Lawrence holds an MBA from Harvard Business School and a Bachelor of Commerce (Honours) from Queen's University.

Prior to January 2009, all of the executive officers held the same positions at the Trust since July 2004 with the exception of Mr. Gary Miller and Mr. James Stannard who became executives of the Trust in February 2008. Prior to February 2008, 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 the Trust. Prior to February 2008, Mr. Stannard held the position of Director of Engineering from May 2007 to February 2008, and Manager of Engineering from June 2004 to May 2007 at the Trust.

Corporate Cease Trade Orders or Bankruptcies

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

The Private Placement Agreement with CPPIB contains a lockup provision, requiring CPPIB to not sell any Shares for an 18 month period following the closing date of the issuance of such Shares, without the consent of the Company. See "*General Development of the Business*".

In addition, CPPIB has agreed, in connection with its subscription for 2,116,800 Shares at a price of \$13.90 per Share, which closed on March 7, 2011, not to sell, or agree to sell (or announce any intention to do so), or otherwise dispose of its economic interest in, any Shares or securities exchangeable or convertible into Shares of the Company for a period of 90 days following the closing of the issuance the 2,116,800 Shares without the prior written consent of BMO Nesbitt Burns Inc. and Scotia Capital Inc., which consent may not be unreasonably withheld, or in certain circumstances relating to a proposed change of control transaction involving the Company. See "*Recent Developments – Share and Fourth Debenture Financing*".

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, Mr. Gary E. Perron and Mr. R. Scott Lawrence.

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, 50, has been the President of Cypress Energy Corp., a private investment company, since March 2008. Prior to this Mr. Archibald was the Chairman & Chief Executive Officer of Cyries from July 2004 to March 2008. Prior thereto 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, 48, is the Executive Vice President and Chief Operating Officer of Cequence Energy Ltd. since September 2010. Prior to this Mr. Crone was the President and CEO of Cequence Energy Ltd. from May 2009 to September 2010. Prior thereto Mr. Crone was an independent businessman from July 2004 to May 2009. Prior thereto 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, 55, is a Managing Director & Senior Vice President with BMO Nesbitt Burns Inc. and has provided investment advisory services for more than 30 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 mutual funds and two limited partnerships. Mr. Perron has considerable public oil and gas experience and serves as a director of several public companies.

Mr. R. Scott Lawrence, 37, is Vice President, Head of Relationship Investments for CPPIB since March 2009. Prior to this he was Senior Principal, Private Investment, and Infrastructure for CPPIB from September 2005 to February 2009. Prior thereto Mr. Lawrence was a Senior Associate for Onex Corporation from June 2001 to May 2004. Mr. Lawrence holds an MBA from Harvard Business School and a Bachelor of Commerce (Honours) from Queen's University.

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 2010 and 2009 were as follows:

	2010	2009
Audit fees	315,000	280,000
Audit related services	110,000	119,000
Tax fees	6,300	4,000
All other fees	64,000	160,000
Total	495,300	563,000

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 \$110,000 in 2010 and \$119,000 in 2009.

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 \$6,300 in 2010 and \$4,000 in 2009.

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 \$64,000 in 2010 and \$160,000 in 2009, which were primarily French translation services.

Reliance on Certain Exemptions

On May 6, 2010, the Company was granted temporary relief pursuant to Part 8 of National Instrument 52-110 – *Audit Committees* ("**NI 52-110**") from the additional independence requirements prescribed by section 1.5 of NI 52-110. Through operation of this section, employment by the Company of a summer intern who was the adult child of a member of the Company's Audit Committee and the payment to the summer intern of a salary for his summer employment, is deemed to be an indirect acceptance of compensation by the member of the Audit Committee and creates a "material relationship", for the purposes of NI 52-110, between the member of the Audit Committee and the Company. Consequently, as a result of this section, the member of the Audit Committee was no longer considered "independent" for the purposes of NI 52-110 and the Company could no longer satisfy the audit committee composition requirements of Section 3.1(3) NI 52-110, which requires every member of the audit committee be "independent" for the purposes of NI 52-110. The board of directors of the Company considered the relationship between member of the Audit Committee and the Company created by the temporary employment of the member of the Audit Committee's adult child and determined that such relationship was not reasonably expected to interfere with the exercise of member of the Audit Committee's independent judgement. Therefore, the Company applied for temporary relief from the additional independence requirements and such relief was granted on May 6, 2010.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings which Progress or any subsidiary of Progress is or was a party to 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 noted below which is as at March 7, 2011:

Name	Number of Common Shares Beneficially Owned, or Controlled or Directed, Directly or Indirectly	Percentage of Issued and Outstanding Common Shares
CPPIB ⁽¹⁾	34,083,488	14.8%

(1) Based on insider reports filed on the System for Electronic Disclosure by Insiders ("SEDI") as at March 10, 2011.

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 Private Placement Agreement;
2. 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, 2010, which note is incorporated herein by reference; and
3. the Debenture Indentures and all supplements thereto governing the First Debentures, Second Debentures, Third Debentures and Fourth Debentures.

Copies of these agreements are available on SEDAR at www.sedar.com.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Shares, Second Debentures, Third Debentures and Fourth Debentures 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 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 May 11, 2011. Additional financial information is provided in Progress' comparative consolidated financial statements and management's discussion and analysis for the year ended December 31, 2010. 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
Website: 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.

**APPENDIX A-1
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON
OIL AND GAS DISCLOSURE**

Report of Management and Directors on Reserve Data and Other Information

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, 2010 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.

February 9, 2011

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

(Signed) "Howard J. 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
FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT RESERVES EVALUATOR OR AUDITOR**

Report on Reserve Data

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

1. We have evaluated the Company's reserve data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the 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, 2010, 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) (S000's)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	Corporate Summary February 7, 2011	Canada	-	\$2,127,812	-	\$2,127,812

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 8, 2011.

(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, 2010, 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 NI 51-101 and 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.

All evaluations of future net revenue set forth below are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ Progress Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. The recovery and reserve estimates described herein are estimates only. Actual reserves may be greater or less than those calculated. 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, 2010
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	3,381	2,916	463	361	468,489	392,700	7,143	5,368	89,069	74,094
Developed non- producing	328	293	0	0	48,390	40,292	669	504	9,062	7,512
Undeveloped	586	512	0	0	302,178	274,436	4,257	3,695	55,207	49,946
Total proved	4,295	3,721	463	361	819,057	707,429	12,070	9,566	153,337	131,553
Probable	1,344	1,133	135	101	543,705	470,874	7,462	6,060	99,559	85,773
Total proved plus probable	5,639	4,854	599	462	1,362,762	1,178,303	19,531	15,626	252,896	217,326

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)											
Proved											
Developed Producing	1,840,528	1,337,244	1,059,190	883,367	762,130	1,840,528	1,337,244	1,059,190	883,367	762,130	14.30
Developed Non-Producing	179,859	122,037	90,420	70,912	57,809	179,859	122,037	90,420	70,912	57,809	12.04
Undeveloped	866,593	498,973	295,910	173,202	93,983	739,087	444,741	270,969	161,005	87,713	5.92
Total Proved	2,886,980	1,958,255	1,445,521	1,127,480	913,923	2,759,475	1,904,022	1,420,580	1,115,284	907,652	10.99
Total Probable	2,312,642	1,167,960	682,291	432,876	287,216	1,734,442	886,189	524,709	336,862	225,284	7.95
Total Proved Plus Probable	5,199,623	3,126,215	2,127,812	1,560,357	1,201,139	4,493,917	2,790,211	1,945,289	1,452,146	1,132,936	9.79

Notes:

- (1) The estimated net present value of future net revenue is based on current legislation in place December 31, 2010.
- (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, 2010, using forecast prices and costs, is set forth below:

(\$ millions)

Reserve Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs	Well Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Forecast Prices and Costs								
Proved	6,336	926	1,786	684	53	2,887	128	2,759
Proved plus probable	11,011	1,612	2,918	1,212	69	5,200	706	4,494

Notes:

- (1) Total revenue includes company revenue before deductions of royalties and includes other income.
- (2) Royalties include Crown, freehold and overriding royalties and mineral tax.

The net present value of future net revenue before income taxes by reserves category and production group as of December 31, 2010, using forecast prices and costs and discounted at 10% per year, is set forth below:

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year)		
		(\$ thousands)	(\$ per BOE)	(\$ per Mcfe)
Proved	Light and medium crude oil ⁽¹⁾	82,598	26.38	4.40
	Heavy oil	7,781	18.53	3.09
	Natural gas ⁽²⁾	1,355,141	10.59	1.76
	Total	1,445,521	10.99	1.83
Proved Plus Probable	Light and medium crude oil ⁽¹⁾	97,643	24.26	4.04
	Heavy oil	9,790	18.23	3.04
	Natural gas ⁽²⁾	2,020,379	9.50	1.58
	Total	2,127,812	9.79	1.63

Notes:

(1) Includes solution gas and other by-products.

(2) Includes by-products but excluding solution gas from oil wells.

The forecast cost and price assumptions herein assume primarily increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the GLJ Progress Report were provided by GLJ and were as follows:

Year	Oil			Natural Gas Liquids			Inflation Rates (%/Year)	Exchange Rate (US\$/Cdn\$)
	WTI Cushing Oklahoma (US\$/bbl)	Edmonton Par Price 40° API (Cdn\$/bbl)	Cromer Medium 29° API (Cdn\$/bbl)	Edmonton Propane (Cdn\$/bbl)	Edmonton Butane (Cdn\$/bbl)	Edmonton Pentanes Plus (Cdn\$/bbl)		
2011	88.00	86.22	82.78	54.32	67.26	90.54	2.0	.98
2012	89.00	89.29	83.04	56.25	68.75	91.96	2.0	.98
2013	90.00	90.92	83.64	57.28	70.01	92.74	2.0	.98
2014	92.00	92.96	84.59	58.56	71.58	94.82	2.0	.98
2015	95.17	96.19	87.54	60.60	74.07	98.12	2.0	.98
2016	97.55	98.62	89.75	62.13	75.94	100.59	2.0	.98
2017	100.26	101.39	92.26	63.87	78.07	103.42	2.0	.98
2018	102.74	103.92	94.57	65.47	80.02	106.00	2.0	.98
2019	105.45	106.68	97.08	67.21	82.15	108.82	2.0	.98
2020	107.56	108.84	99.04	68.57	83.80	111.01	2.0	.98
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	.98

Year	NYMEX Futures Contract (US\$/MMBtu)	Midwest @ Chicago (US\$/MMBtu)	AECO Gas Price (Cdn\$/MMBtu)	Sumas Spot Gas Price (US\$/MMBtu)
2011	4.50	4.60	4.16	4.25
2012	5.15	5.25	4.74	4.85
2013	5.75	5.85	5.31	5.40
2014	6.25	6.35	5.77	5.90
2015	6.75	6.85	6.22	6.40
2016	7.10	7.20	6.53	6.75
2017	7.32	7.42	6.76	6.97
2018	7.47	7.57	6.90	7.12
2019	7.62	7.72	7.06	7.27
2020	7.77	7.87	7.21	7.42
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

Notes:

(1) As at January 1, 2011

(2) Inflation rate for costs

(3) Exchange rate used to generate the benchmark reference prices in this table.

In 2010, Progress received a weighted average price of \$73.24 per Bbl for crude oil, \$55.10 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)
TOTAL PROVED								
Opening Balance	4,070	3,549	521	7,302	541.35	540.12	1,231	101.60
Exploration discoveries	-	-	-	814	43.82	43.82	-	8.12
Drilling extensions and improved recovery	246	246	-	2,662	198.17	198.17	-	35.94
Technical revisions	442	416	26	1,060	(12.19)	(12.19)	-	(0.53)
Acquisitions	1,456	1,456	-	2,018	156.79	156.79	-	29.61
Dispositions	(721)	(721)	-	(437)	(15.87)	(14.72)	(1,153)	(3.80)
Economic Factors	(22)	(20)	(2)	(130)	(15.53)	(15.53)	-	(2.74)
Production	(712)	(631)	(82)	(1,220)	(77.49)	(77.41)	(78)	(14.85)
Closing Balance	4,758	4,295	463	12,070	819.06	819.06	-	153.34
PROBABLE								
Opening Balance	1,168	1046	122	3,435	288.36	288.07	283	52.66
Exploration discoveries	-	-	-	1,031	58.46	58.46	-	10.78
Drilling extensions and improved recovery	140	140	-	2,208	173.96	173.96	-	31.43
Technical revisions	13	2	11	335	(22.82)	(22.82)	-	(3.46)
Acquisitions	385	385	-	550	44.33	44.33	-	8.32
Dispositions	(226)	(226)	-	(135)	(5.25)	(4.96)	(283)	(1.24)
Economic Factors	(1)	(3)	2	38	6.66	6.66	-	1.15
Production	-	-	-	-	-	-	-	-
Closing Balance	1,479	1,344	135	7,462	543.71	543.71	-	99.56
PROVED PLUS PROBABLE								
Opening Balance	5,238	4,595	643	10,737	829.71	828.19	1,514	154.26
Exploration discoveries	-	-	-	1,845	102.28	102.28	-	18.89
Drilling extensions and improved recovery	386	386	-	4,870	372.14	372.14	-	67.28
Technical revisions	455	417	38	1,395	(35.01)	(35.01)	-	(3.99)
Acquisitions	1,841	1,841	-	2,567	201.12	201.12	-	37.93
Dispositions	(947)	(947)	-	(571)	(21.12)	(19.68)	(1,436)	(5.04)
Economic Factors	(23)	(23)	-	(92)	(8,872)	(8.87)	-	(1.59)
Production	(712)	(631)	(82)	(1,220)	(77.49)	(77.41)	(78)	(14.85)
Closing Balance	6,238	5,639	599	19,531	1,362.76	1,362.76	-	252.90

Reserve Additions and Revisions

Reserve additions were primarily due to drilling in northeast BC, targeting the Montney formation. There was also a substantial acquisition of properties from the Foothills Acquisition, which closed March 31, 2010. This acquisition was slightly offset by the disposition of properties in central and southern Alberta, which closed June 30, 2010.

Revisions were slightly negative at less than 4%. A significant portion of this was caused by a substantial decrease in the natural gas price forecast.

Additional Information Relating to Reserve Data

Undeveloped Reserves

Proved Undeveloped Reserves

Nearly all of the Company's proved undeveloped reserves are attributed to drilling locations, with about 60% being Montney wells in northeast BC. Most of the drilling locations are scheduled to be drilled within three years, with over 90% of the associated capital being spent by the end of 2013. The drilling has been scheduled over 3 years instead of 2 years to make the activity level and capital requirements more manageable, and also to have some of the new production come on during times of anticipated higher gas prices.

Gross Reserves First Attributed by Year ⁽¹⁾

	Light & Medium Oil (Mbbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbbl)	Coal Bed Methane (MMcf)	MBOE
	First Attributed	First Attributed	First Attributed	First Attributed	First Attributed
Prior	153	33,869	405	193	6,235
2008	122	35,578	310	117	6,382
2009	57	57,851	861	0	10,561
2010	252	227,113	3,190	0	41,295

Note:

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

Probable Undeveloped Reserves

Nearly all of the Company's proved undeveloped reserves are attributed to drilling locations, with most of the above comments on proved undeveloped reserves also applying to probable undeveloped reserves.

Gross Reserves First Attributed by Year ⁽¹⁾

	Light & Medium Oil (Mbbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbbl)	MBOE
	First Attributed ¹	First Attributed	First Attributed	First Attributed
Prior	73	33,633	383	6,071
2008	52	32,261	265	5,698
2009	19	89,338	998	15,906
2010	127	281,075	3,696	50,669

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.

(\$ thousands)	Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves
Year		
2011	195,939	275,297
2012	293,774	537,219
2013	109,244	261,906
2014	13,871	35,896
2015	36,107	52,257
Remainder	34,978	49,201
Total	683,913	1,211,776

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 2011 of \$196 million on total proved reserves and \$275 million on proved plus probable reserves represent 56 percent and 79 percent of the 2011 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, 2010 the Company had a \$650 million Credit Facility and bank debt of \$313 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, along with other minor operations in both provinces. The core regions provide multi-zone production opportunities and year round access with existing gathering and processing facilities. 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. The Company entered the Deep Basin region in July 2004 and has since that time steadily grown production through drilling and select acquisitions. Progress entered the northeast British Columbia Foothills

region in 2002 with the acquisition of three producing wells, and has steadily grown its production and land position since that time. In 2009, the Company began to focus on the Montney siltstone/shale formation in the Foothills region and will spend a majority of its capital specifically on this play in 2011.

British Columbia Foothills

Approximately 100 kilometres northwest of the city of Fort St. John, British Columbia is the Foothills region, which is a key area of focus for the Company. The region accounts for approximately 65 percent of the Company's production and drilling has historically focused on the Cretaceous and Triassic tight-gas sands. The primary tight-gas target in the region is the Halfway formation, which is a gas charged reservoir approximately 30 to 40 meters thick that can be imaged using modern 3-D seismic data. Secondary Foothills targets include the shallower Bluesky-Gething interval and the deeper Mississippian Debolt formation.

In 2009 the Company began to focus on the Montney formation in the Foothills region. The Montney is a siltstone/shale formation that is over 250 meters thick and pervasive over a large areal extent in northeast British Columbia. Since that time, the Company has completed over 20 vertical wells and 18 horizontal wells in a variety of areas to delineate the size and quality of the Montney resource. Based on those results, the Company has identified six properties ready for commercial development at Town North, Town South, Kobes, Gundy, Caribou and Altares. The Town South property is the most mature in its development, with 12 horizontal wells on production into a 50 MMcf/d facility.

Progress currently holds over 680,000 net acres of land with Montney rights in the Foothills region.

In 2011, management estimates 80 percent of its capital spending will be directed in the Foothills region, primarily focused on the Montney formation.

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, Elmworth and Wapiti areas. This region is characterized by multi-zone, liquids-rich tight 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. Target zones in the region include the, Halfway, Charlie Lake, Nikanassin, Gething, Bluesky, Falher and Dunvegan formations. The area has very well developed infrastructure and the Company has working interests in the Gold Creek, Karr and Wapiti gas plants. Just to the south of Gold Creek is the Copton/Lynx property. Production from Copton/Lynx is primarily from the Cadotte and Cardium formations.

The Deep Basin accounts for approximately 30 percent of the Company's total production. In 2011, management estimates 20 percent of its capital spending will be directed in the Deep Basin region.

Fort St. John Plains

The Fort St. John Plains region is located in close proximity to the city of Fort St. John, British Columbia and accounts for approximately four percent of the Company's total production. This region produces light oil and natural gas from a variety of porous Cretaceous sands and Triassic aged sandstones and carbonates. Wells are typically 1200 to 1700 meters in depth and completed in one to two different formations. Negligible capital will be spent in this region in 2011.

Other Properties

The Company also has minor properties at Ojay and Milo in British Columbia and Pouce Coupe, and Whitecourt in Alberta representing approximately 2 percent of the Company's total production.

Central Alberta

The Central Alberta region was disposed of on June 30, 2010.

The following table indicates the average daily production by operating regions for 2010:

Region	Light and Medium Oil (bbl/d)	Associated And Non-Associated Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	BOE (BOE/d)
Foothills	595	120,782	983	21,708
Fort St. John Plains	532	7,292	59	1,806
Other	-	3,561	-	594
Total British Columbia	1,127	131,635	1,042	24,108
Deep Basin	466	77,496	2,239	15,620
Central Alberta	87	2,979	71	655
Other	277	1,549	13	549
Total Alberta	830	82,024	2,323	16,824
Total daily production	1,957	213,659	3,365	40,932

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, 2010.

	Producing Wells				Non-Producing Wells				Service Wells	
	Oil		Natural Gas		Oil		Natural Gas		Gross	Net
	Gross	Net	Gross	Net	Gross	Net	Gross	Net		
British Columbia	48	30.3	505	410.8	43	24.9	315	235.0	20	13.0
Alberta	89	51.5	324	186.7	28	16.9	149	88.5	14	8.5
Total	137	81.8	829	597.5	71	41.8	464	323.5	34	21.5

Properties with No Attributed Reserves

The following table sets forth the Company's undeveloped land holdings as at December 31, 2010.

	Undeveloped Acres	
	Gross	Net
British Columbia	1,141,000	977,000
Alberta	348,000	300,000
Total	1,489,000	1,277,000

Over the next 12 months approximately 323,000 net acres or 25 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 1,535 gross wells (1,066 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	53	15
Reclamation costs associated with wells that have assigned reserves ⁽¹⁾	24	8
Abandonment and reclamation costs associated with non-producing, shut-in and wells that have no reserves assigned ⁽¹⁾	30	9
Total abandonment and reclamation cost provision	107	32
Portion forecast to be paid during the next three years	6	5

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 2010 the Company incurred the following costs:

(\$ millions)	2010
Property Acquisition Costs – Unproved Properties ⁽¹⁾	38
Property Acquisition (Disposition) Costs – Proved Properties ⁽¹⁾	(9)
Exploration Costs	23
Development Costs	314

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, 2010:

	Development Wells		Exploration Wells		Total Wells	
	(gross)	(net)	(gross)	(net)	(gross)	(net)
Oil wells	1	1	-	-	1	1
Natural gas wells	70	59.9	6	5.4	76	65.3
Dry holes	-	-	-	-	-	-
Total	71	60.9	6	5.4	77	66.3

Progress 2011 capital program has been set at \$350 million. Under the program the Company intends to accelerate the number of Montney wells to be drilled in 2011 to approximately 30 to 35 horizontal wells.

In the first half of 2011, approximately \$100 million will be invested in Montney activities which include the drilling of 14 horizontal wells and three vertical tests. Approximately \$12 million will be invested in compression facilities to handle growing production volumes from new development pods. Approximately \$30 million will be invested in the Company's Deep Basin assets which includes the drilling of 14 wells on its low-risk, multi-zone, liquids rich opportunities in the Gold Creek, Wapiti and Elsworth areas. Approximately \$10 million will be invested in the Company's tight gas opportunities in the Foothills.

2011 Production Estimates

The following table sets out the Company's gross production estimated in the GLJ Progress Report for the year ended December 31, 2011 which is reflected in the estimate of future net revenue disclosed above. There are no fields that account for 20% or more of total production:

Area	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Associated And Non- Associated Gas (Mcf/d)	Natural Gas Liquids (bbl/d)	BOE (Boe/d)
Total Proved Daily Production	1,536	208	238,859	4,247	45,801
Total Probable Daily Production	44	4	17,691	339	3,335
Total Proved Plus Probable	1,580	212	256,549	4,586	49,136

Production History

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

2010					
	Annual	Q4	Q3	Q2	Q1
Natural gas (Mcf/d)	213,659	225,594	222,540	226,898	178,993
Light and medium oil (bbl/d)	1,957	2,127	1,872	2,014	1,812
Natural gas liquids (bbl/d)	3,365	2,974	3,373	3,690	3,426
Total production (BOE/d)	40,932	42,700	42,335	43,520	35,070

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 2010.

2010	Crude Oil				Natural Gas			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
	\$/bbl	\$/bbl	\$/bbl	\$/bbl	\$/Mcf	\$/Mcf	\$/Mcf	\$/Mcf
Average Price Received	63.35	58.69	57.50	61.49	5.69	4.59	4.25	4.31
Realized gain (loss) on financial instruments	-	-	-	-	(0.05)	0.17	0.26	0.33
Royalties	(13.90)	(13.01)	(14.73)	(11.74)	(0.97)	(0.63)	(0.60)	(0.59)
Operating expenses	(11.84)	(13.00)	(15.02)	(17.73)	(0.96)	(1.01)	(0.94)	(0.84)
Transportation expenses	(1.80)	(1.89)	(2.00)	(2.16)	(0.52)	(0.55)	(0.55)	(0.55)
Netback Received	35.81	30.79	25.75	29.86	3.19	2.57	2.42	2.66

2010	Average Selling Price			
	Q1	Q2	Q3	Q4
Light and medium crude (\$/bbl)	75.33	72.97	69.79	74.79
Natural gas liquids (\$/bbl)	52.68	56.40	51.35	60.48
Natural gas (\$/Mcf)	5.27	4.03	3.78	3.68

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.

For the year ended December 31, 2010, approximately 98 percent of our natural gas production was internally marketed. Additionally, approximately 98 percent of crude oil and 99 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>	Minimum Annual Commitment					
	Total	2011	2012	2013	2014	2015
Pipeline commitments	78,577	39,850	15,325	10,005	8,308	5,089

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 11 to the consolidated financial statements for the year ended December 31, 2010.

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.