ANNUAL INFORMATION FORM

YEAR ENDED DECEMBER 31, 2013

March 27, 2014

TABLE OF CONTENTS

GLOSSARY OF TERMS

Selected Defined Terms

"**5.00% Debentures**" means 5.00% convertible unsecured subordinated debentures of the Corporation due January 30, 2015;

"**2012 Secondary Offering**" means the secondary offering by Advantage of 8,300,000 common shares of Longview at a price of $9.00 per common share, which closed on May 22, 2012;

"**2014 Secondary Offering**" means the secondary offering by Advantage of 21,150,010 common shares of Longview at a price of $4.45 per common share, which closed on February 28, 2014;

"**ABCA**" means the *Business Corporations Act* (Alberta), together with any or all regulations promulgated thereunder, as amended from time to time;

"**AOG**" or "**Advantage**" or the "**Corporation**" means Advantage Oil & Gas Ltd., a corporation amalgamation under the ABCA. All references to "**AOG**" or "**Advantage**" or the "**Corporation**", unless the context otherwise requires, are references to Advantage Oil & Gas Ltd. and its predecessors;

"**AOG Board of Directors**" or "**Board of Directors**" or "**Board**" means the board of directors of AOG;

"**Common Shares**" means the common shares of AOG;

"**GAAP**" means generally accepted accounting principles for publicly accountable enterprises in Canada which is currently in accordance with IFRS;

"**IFRS**" means International Financial Report Standards as issued by the International Accounting Standards Board;

"**Longview**" means Longview Oil Corp., a corporation incorporated under the ABCA;

"**Longview Non-Controlling Interest**" means the approximately 54.9% interest of third party minority public shareholders in the common shares of Longview as at December 31, 2013;

"**NYSE**" means the New York Stock Exchange;

"**Shareholders**" means the holders from time to time of one or more Common Shares, as shown on the register of such holders maintained by the Corporation or by the transfer agent of the Common Shares, on behalf of the Corporation;

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

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

Selected Defined Oil and Gas Terms

"**API**" means the American Petroleum Institute;

"**API gravity**" means the American Petroleum Institute gravity expressed in degrees in relation to liquids, which is a measure of how heavy or light a petroleum liquid is compared to water. If a petroleum liquid's API gravity is greater than 10, it is lighter and floats on water; if less than 10, it is heavier than water and sinks. API gravity is thus a measure of the relative density of a petroleum liquid and the density of water, but it is used to compare the relative densities of petroleum liquids;

"**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;

"**Current Production**" means average daily gross production for the three month period ended December 31, 2013;

"**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;

"**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 certainly;

"**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;

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

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems;

"**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 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 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:

(a) 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 referred to as "geological and geophysical costs");

(b) 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;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells;

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

(a) generally accepted as being a reasonable outlook of the future; or

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in subparagraph (a);

"**gross**" means:

(a) in relation to an entity's interest in production and reserves, its "company gross reserves", which are such entity's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interest of such entity;

(b) in relation to wells, the total number of wells in which an entity has an interest; and

(c) in relation to properties, the total area of properties in which an entity has an interest;

"**net**" means:

(a) in relation to an entity's interest in production and reserves, such entity's working interest (operating or non-operating) share after deduction of royalty obligations, plus the entity's royalty interests in production or reserves;

(b) in relation to an entity's interest in wells, the number of wells obtained by aggregating an entity's working interest in each of its gross wells; and

(c) in relation to an entity's interest in a property, the total area in which an entity has an interest multiplied by the working interest owned by it;

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

"**Oil and Natural Gas Properties**" or "**Properties**" means the working, royalty or other interests of AOG in any petroleum and natural gas rights, tangibles and miscellaneous interests, including properties which may be acquired by AOG from time to time;

"**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;

"**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;

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

"**resource play**" refers to drilling programs targeted at regionally distributed crude oil or natural gas accumulations; successful exploitation of these reservoirs is dependent upon technologies such as horizontal drilling and multi-stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas;

"**Total Current Production**" means aggregate average daily gross production from the Properties for the three month period ended December 31, 2013; and

"**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.

Words importing the singular number only include the plural, and *vice versa*, and words importing any gender include all genders. All dollar amounts set forth in this annual information form are in Canadian dollars, except where otherwise indicated.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
NGLs	natural gas liquids
stb	stock tank barrels of oil
Mstb	thousand stock tank barrels of oil
MMboe	million barrels of oil equivalent
boe/d	barrels of oil equivalent per day
bbls/d	barrels of oil per day

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m^3	cubic metres
MMbtu	million British Thermal Units
GJ	Gigajoule

Other

BOE or boe	means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one bbl of oil.
mcfe	means thousand cubic feet of natural gas equivalent, using the ratio of 6 Mcf of natural gas being equivalent to one bbl of oil.
mmcfe	means million cubic feet of natural gas equivalent, using the ratio of 6 Mcf of natural gas being equivalent to one bbl of oil.
WTI	means West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
°API	means the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
psi	means pounds per square inch.

The term "boe" or barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (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. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

CONVERSION

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
bbls	cubic metres	0.159
cubic metres	bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

FORWARD-LOOKING STATEMENTS

Certain statements contained in this annual information form constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this annual information form should not be unduly relied upon. These statements speak only as of the date of this annual information form.

In particular, this annual information form contains forward-looking statements pertaining to, but not limited to, the following:

- the performance characteristics of our assets;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- drilling plans;
- estimated timing of capital expenditures;
- future development plans for the Corporation's assets;
- focus of capital budget;
- timing of development of undeveloped reserves;
- future abandonment and reclamation costs;
- tax horizons;
- timing of completion and terms of disposition of the Corporation's non-core assets and anticipated effect on the Corporation's credit facilities;
- anticipated review of the Corporation's Credit Facility;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditures programs.

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 reserves and resources described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this annual information form are expressly qualified by this cautionary statement.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this annual information form:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- fluctuation in foreign exchange or interest rates;
- stock market volatility and market valuations;

- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; and
- the other factors discussed under "*Risk Factors*".

Although the forward-looking statements contained in this annual information form are based upon assumptions which AOG believe to be reasonable, AOG cannot assure Shareholders that actual results will be consistent with these forward-looking statements. With respect to forward-looking statements contained in this annual information form, AOG has made assumptions regarding, but not limited to: current commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates; future operating costs; that the Corporation will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Corporation’s conduct and results of operations will be consistent with its expectations; that the Corporation will have the ability to develop the Corporation’s oil and gas properties in the manner currently contemplated; that current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated as described herein; and that the estimates of the Corporation’s reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects.

AOG has included the above summary of assumptions and risks related to forward-looking information provided in this annual information form in order to provide Shareholders with a more complete perspective on the Corporation's current and future operations and such information may not be appropriate for other purposes. The Corporation's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits AOG will derive therefrom.

These forward-looking statements are made as of the date of this annual information form and AOG 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.

NON-GAAP MEASURES

The Corporation discloses several financial measures in this annual information form that do not have any standardized meaning prescribed under GAAP. These financial measures include funds from operations and cash netbacks. Management believes that these financial measures are useful supplemental information to analyze operating performance and provide an indication of the results generated by the Corporation’s principal business activities. Investors should be cautioned that these measures should not be construed as an alternative to net income, comprehensive income, and cash provided by operating activities or other measures of financial performance as determined in accordance with GAAP. Advantage’s method of calculating these measures may differ from other companies, and accordingly, they may not be comparable to similar measures used by other companies.

Funds from operations, as presented, is based on cash provided by operating activities before expenditures on asset retirement and changes in non-cash working capital reduced for finance expense excluding accretion. Cash netbacks are dependent on the determination of funds from operations and include the primary cash sales and expenses on a per boe basis that comprise funds from operations.

ADVANTAGE OIL & GAS LTD.

General

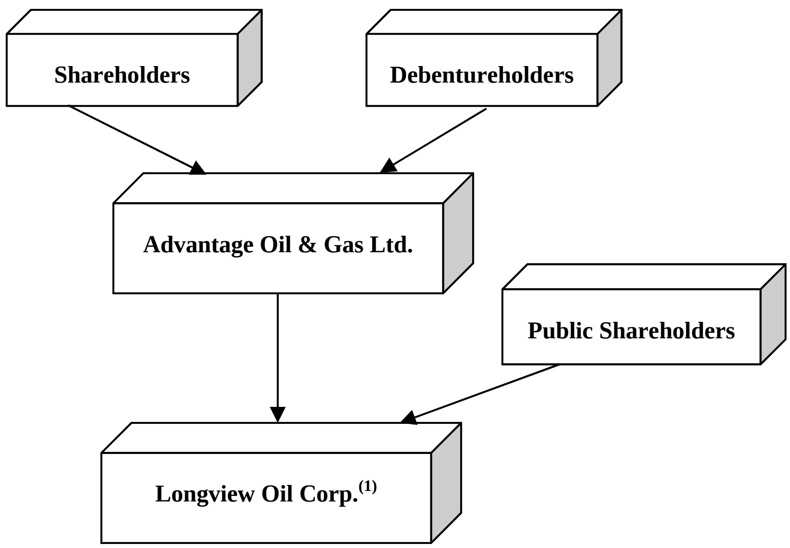
The Corporation was formed pursuant to the amalgamation of Advantage Oil & Gas Ltd., 1335703 Alberta Ltd., SET Resources Inc. and Sound Exchange Co Ltd. under the ABCA on September 5, 2007. On July 9, 2009 the articles of the Corporation were amended to change the number of issued and outstanding Common Shares to equal the number of trust units of Advantage Energy Income Fund (the "**Trust**") outstanding immediately prior to the plan of arrangement pursuant to Section 193 of the ABCA, which closed on July 9, 2009 and pursuant to which, among other things, the Trust was dissolved and the Corporation became the resulting entity.

The Corporation is a reporting issuer in each of the provinces of Canada and the Common Shares are listed on the TSX and NYSE under the symbol "AAV".

The head office of AOG is located at Suite 300, 440-2nd Avenue S.W., Calgary, Alberta T2P 5E9 and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

Corporate Structure

The following diagram illustrates the organizational structure of the Corporation as at December 31, 2013, and, other than Longview, does not include the Corporation's direct or indirect subsidiaries, as the total assets and sales and operating revenues of such other subsidiaries, on a combined basis, does not exceed 10% of the consolidated assets and the consolidated sales and operating revenues of the Corporation.



Note:

(1) On April 14, 2011, Advantage's subsidiary, Longview, completed its initial public offering of common shares (the "**Longview Offering**") and purchased certain oil-weighted assets from Advantage for consideration comprised of cash and 29,450,000 common shares (the "**Longview Transaction**"). As a result of the Longview Offering and the Longview Transaction, Advantage held approximately 63% of the common shares of Longview and the remaining 37% was held by public shareholders. See "*General Development of the Business – 2011*". On May 22, 2012, Longview closed the 2012 Secondary Offering, pursuant to which 8,300,000 common shares of Longview held by Advantage were sold at a price of $9.00 per common share for aggregate gross proceeds to Advantage of $74,700,000. On February 28, 2014, Longview closed the 2014 Secondary Offering, pursuant to which 21,150,010 common shares of Longview held by Advantage were sold at a price of $4.45 per common share for aggregate gross proceeds to Advantage of $94,117,544.50. As a result, as of the date hereof, Advantage does not own or control or direct, directly or indirectly, any common shares of Longview. See "*General Development of the Business – 2012*" and "*General Development of the Business - Recent Developments*".

GENERAL DEVELOPMENT OF THE BUSINESS

General

The Corporation and its subsidiaries are actively engaged in the business of oil and gas exploitation, development, acquisition and production in the Provinces of Alberta and Saskatchewan. The Corporation is focused on development and growth of its extensive Montney natural gas play at Glacier, Alberta. See "*Description of our Business and Operations*" below.

A detailed description of the historical development of the business of the Corporation and its subsidiaries is outlined below. Unless the context otherwise requires, references to "we", "us", "our" or similar terms refer to the Corporation.

Three Year History

2011

Longview Offering and Longview Transaction

On April 14, 2011, Longview completed the Longview Offering and completed the acquisition of certain oil-weighted assets (the "**Acquired Assets**") of the Corporation located in West Central Alberta, Southeast Saskatchewan and the Lloydminster area of Saskatchewan. Pursuant to the Longview Offering, Longview issued 15,000,000 common shares at $10.00 per common share for aggregate gross proceeds of $150,000,000. The over-allotment option granted by Longview to the underwriters pursuant to the Longview Offering to purchase up to an additional 2,250,000 common shares at a purchase price of $10.00 per common share was exercised in full on April 28, 2011.

The purchase price for the Longview Transaction was approximately $554.1 million, prior to closing adjustments pursuant to the terms of the purchase and sale agreement for the Acquired Assets. The purchase price for the Acquired Assets was comprised of the net proceeds of the Longview Offering (including the net proceeds from the exercise of the over-allotment option) in the amount of $162.1 million, the issuance of 29,450,000 common shares to the Corporation and approximately $83.4 million drawn from Longview's credit facilities. As a result of the Longview Offering and the Longview Transaction, Advantage retained an equity ownership interest of approximately 63% of the common shares of Longview.

Concurrent with closing of the Longview Offering, AOG entered into a Technical Services Agreement (the "**TSA**") with Longview. Under the TSA, AOG provided the necessary personnel and technical services to manage Longview's business and Longview reimbursed AOG on a monthly basis for its share of administrative charges based on respective levels of production. During the term of the TSA, the officers of Longview provided services to Longview under the TSA but remained as employees of Advantage. See "*Material Contracts*".

In connection with the Longview Transaction, on April 14, 2011, Longview entered into a credit agreement with a syndicate of financial lenders for an extendible revolving credit facility in the maximum principal amount of $180 million as well as an operating credit agreement with a Canadian financial institution in the maximum principal amount of $20 million (collectively, the "**Longview Credit Facilities**"). See "*Material Contracts*".

As a result of the sale of the assets pursuant to the Longview Transaction, Advantage's borrowing base under its credit facilities was reduced from $525 million to $275 million, comprised of a $20 million revolving operating loan facility and a $255 million extendible revolving credit facility (the "**Credit Facilities**"). Various borrowing options are available under the Credit Facilities, including prime rate based advances, U.S. base rate advances, U.S. dollar LIBOR advances and bankers' acceptances loans. The Credit Facilities are secured by a $1 billion floating charge demand debenture, a general security agreement and a subordination agreement from the Corporation covering all assets and cash flows. The amounts available to the Corporation from time to time under the Credit Facilities are based upon the borrowing base determined by the lenders and which is redetermined on a semi-annual basis by those lenders. The borrowing base constitutes a revolving facility for a 364 day term which is extendible annually for a further 364 day revolving period, subject to a one year term maturity as to lenders not agreeing to such annual extension.

Other Developments

On July 4, 2011, the Board of Directors of AOG approved a capital and operating budget for the twelve month period ending June 30, 2012. The capital budget was focused on a Phase IV development program at Glacier with two key objectives: (i) increase throughput capacity at the Glacier gas plant from 100 MMcf/d to 140 MMcf/d by Q2

2012 and drill a sufficient number of wells to fill the plant; and (ii) further evaluate the Middle and Lower Montney formations.

On December 20, 2011 the board of directors of Longview approved operational guidance and a capital budget of approximately $73 million for the year ending December 31, 2012. The capital budget was primarily focused on oil or oil with liquids rich solution gas projects.

2012

Operational Guidance

On March 22, 2012 Advantage announced that, due to the prevailing low natural gas pricing environment, production at Glacier will be maintained between 90 MMcf/d and 100 MMcf/d and interim guidance was issued for the six months ending June 30, 2012.

Credit Facilities

On May 17, 2012, Advantage announced that the borrowing base under the Credit Facilities had been increased from $275 million to $300 million, comprised of a $20 million revolving operating loan facility and a $280 million extendible revolving credit facility.

2012 Secondary Offering

On May 22, 2012, Longview closed the 2012 Secondary Offering, pursuant to which 8,300,000 common shares of Longview held by Advantage were sold at a price of $9.00 per common share for aggregate gross proceeds to Advantage of $74,700,000. As a result of the 2012 Secondary Offering, Advantage retained an equity ownership interest of approximately 45.2% of the common shares of Longview. See "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*". All of the net proceeds from the 2012 Secondary Offering were initially used to reduce indebtedness under the Credit Facilities. Funds were subsequently utilized to finance additional delineation drilling and development of the Middle Montney formation at Glacier.

Non-Core Asset Dispositions

On August 22, 2012, Advantage announced that it had engaged RBC Capital Markets to market for sale all of the Corporation's non-core assets, being all corporate assets excluding Advantage's core Glacier Montney natural gas asset and its common shares of Longview. The non-core assets produced a total of approximately 6,350 boe/d (80% gas and 20% oil and NGL) during 2012 and had 27.8 MMboe of proved plus probable reserves as at December 31, 2012. Advantage completed two non-core asset dispositions during the third quarter of 2012 for net cash proceeds of $10.9 million and a third non-core asset disposition during the fourth quarter of 2012 for net cash proceeds of $3.0 million (collectively, the "**2012 Non-Core Asset Dispositions**").

2013

Disposition of Non-Core Assets

On February 5, 2013, Advantage announced that it had completed a fourth non-core asset disposition in the first quarter of 2013 for net cash proceeds of $13.9 million and entered into a definitive agreement (the "**Purchase and Sale Agreement**") with Questfire Energy Corp. (the "**Purchaser**") for the sale of non-core assets representing production of approximately 5,900 boe/d (the "**Transaction**") for consideration consisting of $40.2 million of cash, a $32.6 million convertible senior secured debenture (the "**Questfire Debenture**") and 1.5 million Class B shares (the “Class B shares”). The Transaction closed on April 30, 2013.

The net cash proceeds from all five transactions were used to reduce outstanding bank indebtedness under the Credit Facilities. Upon closing of all five transactions, Advantage's major asset was its Glacier Montney property, with production of 90 MMcf/d to 100 MMcf/d, the Corporation's 45.1% holding of the issued and outstanding common shares of Longview, and the Questfire Debenture and Class B Shares issued pursuant to the Transaction.

Appointment of Financial Advisors and Strategic Alternatives Process

Advantage announced on February 5, 2013 that it had retained FirstEnergy Capital Corp. ("**FirstEnergy**") and RBC Capital Markets ("**RBC**") as co-advisors to provide advice as the Corporation initiated the review of strategic alternatives. The Board of Directors believed that the Corporation's core Glacier asset was materially undervalued in the context of the Corporation's current market valuation and Advantage committed to evaluating all options to maximize shareholder value. On February 26, 2013, the Corporation formed a special committee of independent directors (the "**Special Committee**") comprised of Mr. Steven Sharpe, as Chairman and Messrs. Stephen Balog and Ronald McIntosh, to oversee the strategic alternatives review process with the assistance of its financial advisors, FirstEnergy and RBC. The financial advisors commenced a broad marketing effort to solicit interest in a sale of the Corporation or other strategic transaction to maximize value for all shareholders. Technical presentations were completed and following the bid date, the Corporation, along with its financial advisors, reviewed the proposals received from those parties who submitted bids.

Credit Facilities

On April 30, 2013, Advantage announced that the borrowing base under the Credit Facilities had been reduced to $230 million, comprised of a $20 million revolving operating loan facility and a $210 million extendible revolving credit facility. The Credit Facilities were also amended to extend the duration of commodity hedging for up to four years and increase the permitted production available to hedge to 65% of total estimated crude oil and natural gas production on an annual basis over the first three years and 50% over the fourth year.

On October 24, 2013, Advantage announced that its lenders completed their semi-annual review and the borrowing base under the Credit Facilities had been increased to $300 million.

Changes in Directors and Management

On June 12, 2013, Ms. Sheila O'Brien resigned as a director of Advantage. On August 1, 2013, Mr. Kelly Drader resigned as Chief Financial Officer and a director of the Corporation to focus on his role as President and Chief Executive Officer of Longview. Mr. Craig Blackwood, the Vice-President Finance of the Corporation, assumed the role of Interim Chief Financial Officer and on February 4, 2014, Mr. Blackwood was appointed as Chief Financial Officer of the Corporation. On November 28, 2013, Mr. Lionel Derochie resigned as Vice President Operations of the Corporation and on December 31, 2013, Mr. Pat Cairns resigned as Senior Vice President of the Corporation in order to focus on their respective roles at Longview.

Longview Dividend

In order to fund the expansion of its 2014 capital development program, on December 12, 2013 Longview announced a reduction in its monthly dividend from $0.05 per common share to $0.04 per common share effective with the dividend paid on January 15, 2014 to shareholders of record on December 31, 2013.

Recent Developments

Strategic Alternatives Process

On February 4, 2014, the Corporation announced that its strategic alternatives review process had been completed and did not result in an acceptable proposal. During the process, the Corporation received expressions of interest in respect of a variety of potential transactions; however, none of these proposals were determined to be in the best interests of the Corporation and did not adequately reflect the intrinsic value of the Corporation based upon its assets, operations and prospects for growth.

Three Year Development Plan and Glacier Phase VII Budget Approval

On February 4, 2014, the Corporation announced a three year development plan through to 2017 endorsed by the Board and approval of the Glacier Phase VII Capital and Operating Budget for the 12 months ending March 31, 2015. The Corporation's development plan targets doubling production at Glacier to 245 mmcfe/d (40,800 boe/d) in 2017 including the extraction of natural gas liquids and is expected to drive significant cash flow and production per share growth. Based on recent well results and cost performance, Advantage expects this plan can be completed within existing financial facilities. Total capital expenditures during each 12 month development period are estimated to be between $210 million to $270 million with the drilling of approximately 33 wells. The Board approved Phase VII Glacier capital budget targets to increase current production to approximately 183 mmcfe/d in the second quarter of 2015 including approximately 900 bbls/d of natural gas liquids from an initial 25 mmcf/d development in the Middle Montney. Facility expenditures include additional compression, acid gas compression, and power generation. A shallow cut liquids extraction process capable of accommodating future liquids rich gas production growth will be installed at Advantage's current Glacier Gas Plant. Management of Advantage believes significant growth potential exists beyond 2017 supported by the quality and size of Advantage's Montney resource and availability of future pipeline transportation capacity.

Termination of Technical Services Agreement

On February 4, 2014, the Corporation and Longview announced that the TSA was formally terminated and appropriate staffing and systems were in place to enable both organizations to run independently. Consistent with the termination of the TSA, Craig Blackwood resigned as Chief Financial Officer of Longview to focus on his position as Vice President, Finance and Chief Financial Officer of the Corporation and Carey Baker was appointed as Chief Financial Officer of Longview.

Change in Directors and Management

On February 4, 2014, Mr. Steven Sharpe resigned from the Board. Mr Ron McIntosh was elected Interim Chairman.

On February 24, 2014, Longview announced the sudden death of Kelly Drader, the President and Chief Executive Officer and a director of Longview. Mr. Steven Sharpe, Chairman of the Board, was appointed as Interim Chief Executive Officer of Longview until such time as a suitable successor is appointed.

On March 27, 2014, Mr. Neil Bokenfohr, Vice-President Exploitation was appointed as Senior Vice President.

2014 Secondary Offering

On February 28, 2014, Longview closed the 2014 Secondary Offering, pursuant to which 21,150,010 common shares of Longview held by Advantage were sold at a price of $4.45 per common share for net proceeds to Advantage of $90.0 million. As a result of the 2014 Secondary Offering, as of the date hereof, Advantage does not own or control or direct, directly or indirectly, any common shares of Longview. See "*Statement of Reserves Data and Other Oil & Gas Information – Material Changes since December 31, 2013*". All of the net proceeds from the 2014 Secondary Offering were used to reduce indebtedness under the Credit Facilities.

As the 2014 Secondary Offering resulted in Longview becoming a widely held company, on February 10, 2014, the board of directors of Longview adopted a shareholder rights plan agreement (the "**Rights Plan**"). The Rights Plan must be confirmed by shareholders of Longview at a meeting to be held within six months and adoption of the Rights Plan is subject to the acceptance of the TSX.

Sale of Questfire Investments

On March 26, 2014, Advantage entered an agreement for Questfire to repurchase the Questfire Debenture at an aggregate purchase price of $13.6 million. Questfire also agreed that it would make an offer to purchase by way of issuer bid, all of the Class B Shares at a purchase price of $2.60 per share. Advantage expects to receive total proceeds of $17.5 million on the disposition of its investments in Questfire.

Anticipated Changes in the Business

As at the date hereof and other than as disclosed herein, we do not anticipate that any material change in our business will occur during the balance of the 2014 financial year. See "*General Development of the Business – Recent Developments*".

Significant Acquisitions

The Corporation did not complete any acquisitions during the year ended December 31, 2013 for which disclosure is required under Part 8 of National Instrument of 51-102 *Continuous Disclosure Obligations*.

As part of its ongoing business, the Corporation evaluates potential acquisitions of all types of petroleum and natural gas assets. The Corporation 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 Corporation has not reached agreement on the price or terms of any potential material acquisitions. The Corporation cannot predict whether any current or future opportunities will result in one or more acquisitions for the Corporation.

DESCRIPTION OF OUR BUSINESS AND OPERATIONS

General

AOG and its subsidiaries are actively engaged in the business of oil and gas exploitation, development, acquisition and production in the provinces of Alberta and Saskatchewan.

Advantage's exploitation and development program is focused primarily at Glacier, Alberta where it is developing a significant natural gas resource play. As current and future practice, AOG has established a financial hedging strategy and may manage the risk associated with changes in commodity prices by entering into derivatives. See "*Risk Factors*". Although Advantage has a significant capital development program, it also actively pursues growth opportunities through oil and gas asset acquisitions, as well as through corporate acquisitions. AOG targets acquisitions that are accretive to net asset value and that increase our reserve and production base per Common Share outstanding. Acquisitions must also meet reserve life index criteria and exhibit low risk opportunities to increase reserves and production. It is currently intended that AOG will finance acquisitions and investments through the Credit Facilities, the issuance of additional Common Shares from treasury and the issuance of subordinated convertible debentures, maintaining prudent leverage.

Reorganizations

As at the date hereof, other than the Longview Transaction, there have been no material reorganizations of AOG and or any of our subsidiaries within the three most recently completed financial years and there are currently no material reorganizations of AOG proposed for the current financial year. See "*General Development of the Business*".

Bankruptcy and Similar Procedures

There have been no bankruptcy, receivership or similar proceedings against the Corporation or any of its subsidiaries or related entities, or any voluntary bankruptcy, receivership or similar proceeding by the Corporation or any of its subsidiaries or related entities since the inception of the Corporation or during or proposed for the current financial year.

Human Resources

As at December 31, 2013, the Corporation employed 80 full-time employees, 63 of which are located in the head office and 17 of which are located in the field. We also retained 17 consultants in the head office.

As a result of the termination of the TSA with Longview, as at March 27, 2014, the Corporation employed 25 full-time employees, 21 of which are located in the head office and 4 of which are located in the field. We also retained 12 consultants in the head office. See "*General Development of the Business – Recent Developments*".

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The report of management and directors on oil and gas disclosure in Form 51-101F3 and the report on consolidated reserves data by Sproule Associates Limited ("**Sproule**") in Form 51-101F2 are attached as Schedules "A" and "B" to this annual information form, respectively, which forms are incorporated herein by reference.

The consolidated statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated December 31, 2013. The effective date of the Statement is December 31, 2013 and the preparation date of the Statement is December 2013 to March 2014.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by Sproule with an effective date of December 31, 2013 contained in a consolidated report of Sproule dated March 14, 2014 (the "**Sproule Consolidated Report**"). The Sproule Consolidated Report evaluated, as at December 31, 2013, the oil, NGLs and natural gas reserves of AOG and its consolidated subsidiaries, including Longview. The Reserves Data summarizes AOG's consolidated oil, NGLs and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. In accordance with NI 51-101, the Sproule Consolidated Report includes 100% of the reserves and future net revenue attributable to Longview's properties, without reduction to reflect the approximately 54.9% third-party minority interests in Longview as at December 31, 2013. Accordingly, the Reserves Data for the Corporation's consolidated reserves set forth below, which has been derived from the Sproule Consolidated Report, reflects 100% of Longview's reserves and future net revenue without reduction to reflect the Longview Non-Controlling Interest. Approximately 6.2% of the assigned total gross proved plus probable reserves and 12.3% of the total gross proved plus probable future net revenue discounted at 10% before taxes in the Sproule Consolidated Report is attributable to the Longview Non-Controlling Interest as at December 31, 2013. See "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*". On February 28, 2014, Longview completed the 2014 Secondary Offering and Advantage ceased to own or control or direct, directly or indirectly, any common shares of Longview. See "*Statement of Reserves Data and Other Oil & Gas Information – Material Changes since December 31, 2013*".

The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which the Corporation believes is important to readers of this annual information form. Sproule was engaged to provide evaluations of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of our consolidated reserves are in Canada and, specifically, in the provinces of Alberta and Saskatchewan.

There are numerous uncertainties inherent in estimating quantities of crude oil, natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this annual information form 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 natural 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 crude oil, NGL and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its consolidated reserves will vary from estimates thereof and such variations could be material.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of our crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

The information relating to the Corporation's consolidated crude oil, NGL and natural gas reserves contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment costs. See "*Forward-Looking Statements*", "*Industry Conditions*" and "*Risk Factors – Reserves Estimates*".

In certain of the tables set forth below, the columns may not add due to rounding.

SUMMARY OF OIL AND GAS RESERVES
as at December 31, 2013
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY[(1)]	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	8,066.4	7,064.9	1,164.5	1,051.3
Developed Non-Producing	534.5	500.1	51.6	45.9
Undeveloped	3,326.2	2,916.5	298.8	235.4
TOTAL PROVED	11,927.1	10,481.4	1,514.9	1,332.6
PROBABLE	10,741.1	9,218.8	2,987.9	2,780.3
TOTAL PROVED PLUS PROBABLE	22,668.3	19,700.2	4,502.7	4,112.9

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY[(1)]	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	220,142	206,820	1,809.5	1,346.5
Developed Non-Producing	27,793	26,310	248.6	193.6
Undeveloped	770,083	725,798	6,713.9	5,472.4
TOTAL PROVED	1,018,018	958,928	8,772.1	7,012.5
PROBABLE	646,733	583,325	7,081.4	5,228.0
TOTAL PROVED PLUS PROBABLE	1,664,751	1,542,253	15,853.5	12,240.5

	RESERVES	
	TOTAL OIL EQUIVALENT	
RESERVES CATEGORY[(1)]	Gross (Mboe)	Net (Mboe)
PROVED		
Developed Producing	47,730.8	43,932.7
Developed Non-Producing	5,466.8	5,124.5
Undeveloped	138,686.1	129,590.4
TOTAL PROVED	191,883.8	178,647.8
PROBABLE	128,599.3	114,448.0
TOTAL PROVED PLUS PROBABLE	320,483.1	293,095.8

Note:

(1) All reserves presented herein represent the Corporation's and the Corporation's consolidated subsidiaries interest. The Reserves Data reflects 100% of Longview's reserves and future net revenue without reduction to reflect the Longview Non-Controlling Interest. As at December 31, 2013, the Corporation held approximately 45.1% interest in Longview. For further discussion see "*Statement of*

Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves".

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2013
FORECAST PRICES AND COSTS

RESERVES CATEGORY[(2)]	Before Income Tax Discounted at (%/year) 0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	After Income Taxes Discounted at (%/year) 0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	Unit Value Before Income Tax Discounted at 10%/ year[(1)] ($/boe)
PROVED											
Developed Producing	1,220,329	903,097	730,111	620,028	543,261	1,220,329	903,097	730,111	620,028	543,261	16.62
Developed Non-Producing	141,454	105,684	85,502	72,222	62,710	141,454	105,684	85,502	72,222	62,710	16.68
Undeveloped	2,767,576	1,377,629	768,359	452,401	270,371	2,142,518	1,079,633	605,047	355,000	208,839	5.93
TOTAL PROVED	4,129,359	2,386,412	1,583,972	1,144,651	876,341	3,504,301	2,088,414	1,420,660	1,047,250	814,810	8.87
PROBABLE	3,917,617	1,916,979	1,148,751	769,106	551,471	2,932,200	1,432,837	859,813	577,991	416,954	10.04
TOTAL PROVED PLUS PROBABLE	8,046,975	4,303,391	2,732,723	1,913,756	1,427,813	6,436,500	3,521,252	2,280,473	1,625,241	1,231,763	9.32

Notes:

(1) The unit values are based on net reserve volumes.

(2) All reserves presented herein represent the Corporation's and the Corporation's consolidated subsidiaries interest. The Reserves Data reflects 100% of Longview's reserves and future net revenue without reduction to reflect the Longview Non-Controlling Interest. As at December 31, 2013, the Corporation held an approximately 45.1% interest in Longview. For further discussion see "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

(3) Values are calculated by considering existing tax pools for Advantage in the evaluation of Advantage's oil and gas properties, and take into account current federal tax regulations. Values do not represent an estimate of the value at the business entity level, which may be significantly different. For information at the business entity level, please see Advantage's Consolidated Financial Statements and Management's Discussion and Analysis for the year ended December 31, 2013.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
as at December 31, 2013
FORECAST PRICES AND COSTS

RESERVES CATEGORY[(1)]	REVENUE ($000's)	ROYALTIES ($000's)	OPERATING COSTS ($000's)	DEVELOP-MENT COSTS ($000's)	ABANDONMENT AND RECLAMATION COSTS ($000's)	FUTURE NET REVENUE BEFORE FUTURE INCOME TAXES ($000's)	FUTURE INCOME TAXES ($000's)	FUTURE NET REVENUE AFTER FUTURE INCOME TAXES ($000's)
Proved Reserves	7,779,504	578,930	1,494,951	1,533,887	42,376	4,129,359	625,058	3,504,301
Proved Plus Probable Reserves	13,861,504	1,241,962	2,450,119	2,066,384	56,064	8,046,975	1,610,475	6,436,500

Note:

(1) All reserves presented herein represent the Corporation's and the Corporation's consolidated subsidiaries interest. The Reserves Data reflects 100% of Longview's reserves and future net revenue without reduction to reflect the Longview Non-Controlling Interest. As at December 31, 2013, the Corporation held an approximately 45.1% interest in Longview. For further discussion see "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

FUTURE NET REVENUE
BY PRODUCTION GROUP
as at December 31, 2013
FORECAST PRICES AND COSTS

RESERVES CATEGORY[1]	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000's)	UNIT VALUE ($/boe)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	299,097	23.24
	Heavy Oil (including solution gas and other by-products)	31,546	22.09
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	1,253,329	7.62
	Non-Conventional Oil and Gas Activities (Coalbed Methane)	-	-
	TOTAL	1,583,972	8.86
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	492,780	21.19
	Heavy Oil (including solution gas and other by-products)	76,722	18.07
	Natural Gas (including by-products but excluding solution gas and by-products from oil wells)	2,163,221	8.14
	Non-Conventional Oil and Gas Activities (Coalbed Methane)	-	-
	TOTAL	2,732,723	9.32

Note:

(1) All reserves presented herein represent the Corporation's and the Corporation's consolidated subsidiaries interest. The Reserves Data reflects 100% of Longview's reserves and future net revenue without reduction to reflect the Longview Non-Controlling Interest. As at December 31, 2013, the Corporation held an approximately 45.1% interest in Longview. For further discussion see "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

Pricing Assumptions

The following tables set forth the benchmark reference prices, as at December 31, 2013, reflected in the Reserves Data. These price assumptions were provided to us by Sproule and were Sproule's then current forecasts at the date of the Sproule Report.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS[1]
as at December 31, 2013
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Light Sweet Crude Oil at Edmonton 40º API ($Cdn/bbl)	Cromer Crude Oil 35º API ($Cdn/bbl)	Hardisty Heavy 12º API ($Cdn/bbl)	NATURAL GAS AECO-C Spot ($Cdn/ MMBtu)	NATURAL GAS LIQUIDS Edmonton Pentanes Plus ($Cdn/bbl)	NATURAL GAS LIQUIDS Edmonton Butanes ($Cdn/bbl)	INFLATION RATES %/Year	EXCHANGE RATE [2] ($US/$Cdn)
2014	94.65	92.64	90.64	70.40	4.00	103.50	69.05	1.5	0.94
2015	88.37	89.31	87.31	67.88	3.99	99.78	66.57	1.5	0.94
2016	84.25	89.63	87.63	68.12	4.00	100.14	66.81	1.5	0.94
2017	95.52	101.62	99.62	77.23	4.93	113.53	75.74	1.5	0.94
2018	96.96	103.14	101.14	78.39	5.01	115.24	76.88	1.5	0.94
2019	98.41	104.69	102.69	79.57	5.09	116.97	78.03	1.5	0.94
2020	99.89	106.26	104.26	80.76	5.18	118.72	79.20	1.5	0.94
2021	101.38	107.86	105.86	81.97	5.26	120.50	80.39	1.5	0.94
2022	102.91	109.47	107.47	83.20	5.35	122.31	81.60	1.5	0.94
2023	104.45	111.12	109.12	84.45	5.43	124.14	82.82	1.5	0.94
2024	106.02	112.78	110.78	85.71	5.52	126.01	84.06	1.5	0.94
Thereafter	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	0.94

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.
(2) The exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices, including hedging, realized by the Corporation for the year ended December 31, 2013, were $3.11/Mcf for natural gas, $80.52/bbl for crude oil, and $58.154/bbl for NGLs.

Reconciliations of Changes in Reserves

The following table sets forth a reconciliation of the Corporation's total gross proved, total gross probable and total gross proved plus probable reserves as at December 31, 2013 against such reserves as at December 31, 2012 based on forecast prices and cost assumptions.

RECONCILIATION OF
GROSS RESERVES[(1)]
BY PRODUCT TYPE
FORECAST PRICES AND COSTS

	Light And Medium Oil			Heavy Oil			Natural Gas Liquids		
FACTORS	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2012	14,600.9	10,198.7	24,799.6	1,769.2	2,841.9	4,611.1	6,016.9	3,027.8	9,044.7
Extensions	784.4	968.7	1,753.1	26.9	258.4	285.3	3,107.2	3,737.0	6,844.2
Improved Recovery	-	-	-	-	-	-	-	-	-
Infill Drilling	428.6	182.7	611.3	45.5	25.5	71.0	81.6	26.7	108.3
Technical Revisions	(1,263.4)	146.4	(1,117.0)	(4.0)	72.3	68.3	2,338.1	1,419.2	3,757.3
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(1,304.6)	(834.3)	(2,139.0)	(136.4)	(218.6)	(355.0)	(2,476.7)	(1,114.2)	(3,590.9)
Economic Factors	112.9	79.0	191.9	15.7	8.3	24.0	(10.6)	(15.0)	(25.6)
Production	(1,431.6)	-	(1,431.6)	(202.0)	-	(202.0)	(284.5)	-	(284.5)
December 31, 2013	11,927.1	10,741.2	22,668.3	1,514.9	2,987.8	4,502.7	8,772.1	7,081.4	15,853.5

	Associated and Non-Associated Gas			Oil Equivalent		
FACTORS	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (MBoe)**	**Probable (MBoe)**	**Proved Plus Probable (MBoe)**
December 31, 2012	1,013,771	590,868	1,604,639	191,348.9	114,546.2	305,895.1
Extensions	98,896	104,627	203,523	20,401.1	22,401.9	42,803.1
Improved Recovery	-	-	-	-	-	-
Infill Drilling	893	291	1,184	704.5	283.4	987.9
Technical Revisions	51,948	640	52,588	9,728.5	1,744.9	11,473.4
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	(102,154)	(48,465)	(150,619)	(20,943.3)	(10,244.7)	(31,188.0)
Economic Factors	(1,105)	(1,228)	(2,333)	(66.3)	(132.4)	(198.7)
Production	(44,230)	-	(44,230)	(9,289.8)	-	(9,289.8)
December 31, 2013	1,018,018	646,733	1,664,751	191,883.7	128,599.3	320,483.0

Note:

(1) All reserves presented herein represent the Corporation's and the Corporation's consolidated subsidiaries interest. The Reserves Data reflects 100% of Longview's reserves and future net revenue without reduction to reflect the Longview Non-Controlling Interest. As at December 31, 2013, the Corporation held an approximately 45.1% interest in Longview. For further discussion see "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

Ownership of Longview - Interests of Minority Shareholders in Longview Reserves

On April 14, 2011, Longview completed the Longview Offering and the Longview Transaction. The purchase price for the Longview Transaction was approximately $554.1 million, prior to closing adjustments pursuant to the terms of the purchase and sale agreement for the Acquired Assets. The purchase price for the Acquired Assets was comprised of the net proceeds of the Longview Offering (including the net proceeds from the exercise of the over-allotment option) in the amount of $162.1 million, the issuance of 29,450,000 common shares to the Corporation and approximately $83.4 million drawn from Longview's credit facilities. On May 22, 2012, Longview closed the 2012 Secondary Offering, pursuant to which 8,300,000 common shares of Longview held by Advantage were sold at a price of $9.00 per common share for aggregate gross proceeds to Advantage of $74,700,000. As a result of the 2012 Secondary Offering, as at December 31, 2013, the Corporation held an approximately 45.1% equity interest in Longview.

As at December 31, 2013, the Sproule Consolidated Report estimated Longview's share of proved, probable and proved plus probable reserves, representing 100% of the working interest of Longview, which were consolidated in the Corporation's reserves. Third-party minority shareholders indirectly owned approximately 54.9% of these reserves at December 31, 2013. The tables below represent a summary of reserves indirectly owned by Longview's third-party minority shareholders and a summary of the net present value (before tax) of such reserves, all as at December 31, 2013. All reserves stated herein are based on forecast prices and costs.

SUMMARY OF OIL AND GAS RESERVES
as at December 31, 2013
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		HEAVY OIL	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	4,425.2	3,875.8	639.3	577.2
Developed Non-Producing	293.4	274.6	28.3	25.2
Undeveloped	1,826.1	1,601.2	164.0	129.2
TOTAL PROVED	6,544.7	5,751.4	831.6	731.6
PROBABLE	5,896.4	5,060.7	1,640.4	1,526.4
TOTAL PROVED PLUS PROBABLE	12,441.1	10,812.1	2,472.0	2,258.0

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
PROVED				
Developed Producing	8,174.1	7,331.3	577.1	427.2
Developed Non-Producing	79.6	79.1	2.8	3.0
Undeveloped	5,851.8	5,434.6	345.8	277.8
TOTAL PROVED	14,105.5	12,845.0	925.7	708.0
PROBABLE	11,103.0	10,057.7	621.9	463.7
TOTAL PROVED PLUS PROBABLE	25,208.5	22,902.7	1,547.6	1,171.7

RESERVES CATEGORY	RESERVES TOTAL OIL EQUIVALENT Gross (Mboe)	Net (Mboe)
PROVED		
Developed Producing	7,003.9	6,102.0
Developed Non-Producing	338.0	316.0
Undeveloped	3,311.2	2,914.0
TOTAL PROVED	10,653.1	9,331.9
PROBABLE	10,009.1	8,727.1
TOTAL PROVED PLUS PROBABLE	20,662.2	18,059.0

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2013
FORECAST PRICES AND COSTS

	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/ year(1)
RESERVES CATEGORY	**0% ($000's)**	**5% ($000's)**	**10% ($000's)**	**15% ($000's)**	**20% ($000's)**	**0% ($000's)**	**5% ($000's)**	**10% ($000's)**	**15% ($000's)**	**20% ($000's)**	**($/boe)**
PROVED											
Developed Producing	238,373	178,740	145,151	123,285	107,841	238,373	178,740	145,151	123,285	107,841	23.79
Developed Non-Producing	13,089	10,650	8,945	7,677	6,697	13,089	10,650	8,945	7,677	6,697	28.31
Undeveloped	89,534	60,286	41,776	29,343	20,610	74,040	49,926	34,567	24,163	16,789	14.34
TOTAL PROVED	340,995	249,676	195,872	160,304	135,147	325,501	239,315	188,663	155,125	131,327	20.99
PROBABLE	426,637	223,929	141,204	97,394	70,590	315,982	164,433	102,392	69,533	49,460	16.18
TOTAL PROVED PLUS PROBABLE	767,632	473,605	337,076	257,698	205,738	641,483	403,748	291,056	224,658	180,787	18.67

Note:

(1) The unit values are based on net reserve volumes.

Additional Information Relating to Reserves Data

Unless otherwise indicated, the additional information contained in this section pertains to Advantage and Longview on a consolidated basis and references to Advantage include Longview (without reduction to reflect the Longview Non-Controlling Interest). See "*Statement of Reserves Data and Other Oil & Gas Information - Ownership of Longview - Interests of Minority Shareholders in Longview Reserves*".

On February 28, 2014, Longview completed the 2014 Secondary Offering and Advantage ceased to own or control or direct, directly or indirectly, any common shares of Longview. See "*Statement of Reserves Data and Other Oil & Gas Information – Material Changes since December 31, 2013*".

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Proved and probable undeveloped reserves have been assigned in accordance with engineering and geological practices as defined under NI 51-101. In general, undeveloped reserves are planned to be developed over the next two years.

In some cases, it will take longer than two years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*" herein

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, first attributed to us in each of the following financial years.

Proved Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2011	1,391	3,768	311	452	88,461	562,420	5	513
2012	761	3,946	38	292	76,636	704,128	1,824	2,342
2013	938	3,326	53	299	47,142	770,083	1,181	6,714

Sproule has assigned 138.7 MMboe of gross proved undeveloped reserves in the Sproule Report under forecast prices and costs, together with $1.5 billion of associated undiscounted future capital expenditures. Proved undeveloped capital spending in the first two forecast years of the Sproule Report accounts for $359.5 million, or 23.4%, of the total forecast. These figures increase to $788.3 million or 51.4%, during the first five years of the Sproule Report.

Probable Undeveloped Reserves

	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
2011	1,636	6,212	125	2,152	23,940	360,510	12	756
2012	747	6,535	39	2,102	110,943	475,826	944	1,676
2013	959	7,476	265	2,522	33,104	562,041	1,202	6,087

Sproule has assigned 109.8 MMboe of gross probable undeveloped reserves and has allocated future development capital of $532.5 million to all gross probable undeveloped reserves with $233.8 million scheduled for the first five years.

Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on production forecasts, prices and economic conditions. The Corporation's reserves are evaluated by Sproule.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, commodity prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

In addition, high operating costs substantially reduce our netback, which in turn reduces the amount of cash available for reinvestment in drilling opportunities. This becomes most relevant during periods of low commodity prices when profits are more significantly impacted by high costs.

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.

	Forecast Prices and Costs	
Year	**Proved Reserves (MM$)**	**Proved Plus Probable Reserves (MM$)**
2014	158.3	198.4
2015	201.2	278.1
2016	152.4	206.2
2017	154.8	173.2
2018	121.6	166.3
Total: Undiscounted for all years	1,533.9	2,066.4

To fund our capital program, including future development costs, we have many financing alternatives available, including partial retention of cash flow from operations, bank debt financing, issuance of additional Common Shares, and issuance of convertible debentures. We evaluate the appropriate financing alternatives closely and have made use of all these options dependent on the given investment situation and the capital markets. We maintain a capital structure that is similar to our industry peer group and that are intended to maximize the investment return to Shareholders as compared to the cost of financing. We expect to continue using all financing alternatives available to continue pursuing our oil and gas development strategy. The assorted financing instruments have certain inherent costs which we consider in the economic evaluation of pursuing any development opportunity.

There can be no guarantee that funds will be available or that we will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop those reserves would have a negative impact on future production and cash flow and could result in negative revisions to our reserves.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Corporation does not anticipate that interest or other funding costs would make further development of any of the Corporation's assets uneconomic.

Other Oil and Gas Information

AOG's properties are spread geographically throughout the Western Canadian Sedimentary Basin. This sedimentary basin covers a large portion of the four western Canadian provinces, with the majority of the Corporation's properties concentrated in Alberta and Saskatchewan. These properties produce from a variety of various aged geological formations and reservoirs. The Corporation operates over 85% of its properties, which allows the Corporation to control the nature and timing of the capital investments necessary to maximize the potential in developing these assets. AOG's properties can be divided on the broad basis of commodity and of production type. Light or medium gravity oil accounts for 18% of Current Production and 13% of gross proved reserves, and natural gas accounts for 82% of Current Production and 87**%** of gross proved reserves.

The following property descriptions are as of December 31, 2013 unless otherwise noted and reserves quoted are as reported in the Sproule Report. The following property descriptions reflect the disposition of certain of the Corporation's non-core assets pursuant to the 2012 Non-Core Asset Dispositions, the non-core asset disposition completed in the first quarter of 2013 and the non-core assets sold pursuant to the Transaction. See "*General Development of the Business – 2013*". Further, the following property descriptions include the properties held by Longview as at December 31, 2013.

On February 28, 2014, Longview completed the 2014 Secondary Offering and Advantage ceased to own or control or direct, directly or indirectly, any common shares of Longview. See "*Statement of Reserves Data and Other Oil & Gas Information – Material Changes since December 31, 2013*".

Property Descriptions

Advantage Oil & Gas Ltd.

Glacier, Alberta

The Glacier property lies along the Alberta side of the border with British Columbia between Grande Prairie, Alberta and Dawson Creek, British Columbia. The primary zones of interest are within the Triassic Montney and Doig formation siltstones. The Glacier property consists of 82 gross (76 net) sections of land with Doig/Montney interests. The total thickness of the Lower Doig/Montney is up to 300 metres and lends itself to multiple layers of development which contributes to the significant inventory of undrilled wells within this resource play. Based on current reserves assignments as of December 31, 2013, Glacier has a proved plus probable reserve life index ("RLI") of 43 years at a production rate of 108.1 MMcf/d, which was the average production rate achieved at Glacier during the fourth quarter of 2013.

Since the spud of the first horizontal well on July 26, 2008 to the end of December 2013, Advantage has drilled and completed 108 gross (98.5 net) horizontal wells at the Glacier property in either the Triassic Montney or Doig formation siltstones. One vertical well, drilled in 2010, into the underlying Belloy Formation was completed for use as an acid gas disposal well and one vertical well drilled in the first quarter of 2013 is used as a service well and supplements our water disposal system.

In 2013, Advantage drilled 16 gross (16 net) horizontal wells in the Montney and Lower Doig formations on the Glacier property. Additionally, Advantage drilled one vertical well in the first quarter of 2013 proximal to the 05-02-76-12W6 plant site that is used as a service well and supplements our water disposal system.

During 2013 Advantage acquired an additional 43.25 gross (43.25 net) sections of new Montney acreage in close proximity to the producing Glacier asset that will be evaluated for prospective natural gas and liquids potential. In aggregate Advantage now holds 121 net sections of land with either Doig or Montney potential for both natural gas and liquids.

During 2013 and Q1 2014, Advantage continued with its program to delineate the Glacier land block vertically by drilling and testing wells in intervals other than the historically drilled Doig and Lower Montney. To date, a total of 9 horizontal wells and 3 vertical recompletions have tested intervals other than the Lower Doig or Lower Montney. This development has resulted in significant delineation and de-risking of the liquid rich Middle Montney resource potential at Glacier.

Advantage owns and operates a 100% working interest gas plant located at 5-02-76-12W6. The plant has a licenced throughput capacity of 160 MMcf/d of raw gas. All gas is sold through Advantage’s 22 kilometer sales pipeline into the TransCanada pipeline system. The operating cost structure of the Glacier field is very favorable. Combined field and plant operating costs averaged approximately $0.30/Mcfe during 2013.

Glacier production is currently at approximately 135 MMcfe/d or 22,500 boe/d which represents virtually 100% of the Corporation's total production.

The Sproule Report assigns 991.3 bcf of gross (934.7 bcf of net) proved natural gas reserves and 7.1 MMbbls of gross (5.7 MMbbls of net) proved NGL reserves to this property. In addition, 626.3 bcf of gross (564.9 bcf of net) probable natural gas reserves and 5.9 MMbbls of gross (4.4 MMbbls of net) probable NGL reserves have been assigned to this property.

Longview Oil Corp. - Major Properties

West Central Alberta

This area consists of a number of individual properties and lands located in the West Central area of Alberta. Current Production from this area was approximately 2,897 boe/d and is comprised mainly of low decline, high netback light oil. Production is derived from numerous large oil pools where opportunities exist to increase production and reserves through low risk development drilling and the application of enhanced oil recovery techniques. Drilling opportunities also exist for step-out and exploration drilling on undeveloped lands.

Nevis, Alberta

Nevis is an operated property which is situated 60 kilometres east of Red Deer, Alberta. Nevis is Longview's largest producing property with Current Production of approximately 1,406 boe/d. The property is divided into two main Wabamun oil pools each trapped structurally and stratigraphically. Crude oil quality averages 39^{o} API which also produces associated natural gas and NGLs. Two operated facilities are utilized for processing the oil and natural gas production which is gathered from the wells through pipelines to the respective central facilities. Clean oil is trucked from the facilities and water is disposed of back into the reservoir. Associated gas is transported through pipelines to third party compression and sales.

The main producing zone is the Devonian age Wabamun Formation, which occurs at 1,600 metres of depth. This reservoir is a high porosity, low permeability carbonate which results in relatively low production inflow from vertical wells. As a result, horizontal drilling technology is used to increase inflow from the low permeability rock with current development drilling downspaced to six wells per section. Production has increased and the ultimate recovery has been enhanced through increased well density as a result of receiving regulatory approval to downspace portions of this property. Horizontal well laterals are on average 1,200 metres in length.Wells are completed on an open hole basis and only require an acid wash as stimulation to clean the wellbore before being placed on production. Work is ongoing to evaluate the merits of multi-stage fracing techniques to enhance both productivity and injectivity across the reservoir.

In the eastern pool, a 6 well pilot waterflood scheme has been implemented to evaluate the potential for enhanced recovery of these pools. Longview is also studying the feasibility of CO_2 flood applications to enhance production recovery and reserves at Nevis.

The Sproule Report assigns 14.4 bcf of gross (12.7 bcf net) proved natural gas reserves and 3,158 Mbbls of gross (2,572 Mbbls net) proved crude oil and NGL reserves to this property. In addition, 5.9 bcf of gross (5.2 bcf net) probable natural gas reserves and 1,469 Mbbls of gross (1,176 Mbbls net) probable crude oil and NGL reserves have been assigned to this property.

Westerose, Alberta

The Westerose property is located approximately 60 kilometres southwest of Edmonton, Alberta and consists mainly of the Westerose Banff "C" Unit, the Chip Lake Rock Creek pool and the Rose Creek Pembina Cardium Unit as well as- other interests in several oil and liquids rich natural gas pools in the general vicinity which includes some minor interests in some Pembina Cardium oil units. Current Production from the Westerose area was approximately 413 boe/d.

The Sproule Report assigned 1.7 bcf of gross (1.6 bcf net) proved natural gas reserves and 1,469 Mbbls of gross (1,261 Mbbls net) proved crude oil and NGL reserves to the Westerose property. In addition, 0.9 bcf of gross (0.8

bcf net) probable natural gas reserves and 1,782 Mbbls of gross (1,415 Mbbls net) probable crude oil and NGL reserves have been assigned to this property.

Westerose Banff "C" Unit

The Westerose Banff "C" Unit (52% unit interest) produces 29^{o} API gravity crude oil which is trapped stratigraphically along the erosional subcrop edge of the Mississippian Banff Formation. The reservoir in the Banff Formation is a dolomitized carbonate which occurs at a depth of 1,800 metres. The Westerose Banff "C" Unit is currently developed on 40 acre spacing with four water injection wells. This reservoir is currently under an active waterflood pressure maintenance scheme which commenced in 2003 and production is responding positively to injection. Additional infill drilling and injector conversions are being evaluated to improve ultimate oil recovery.

Chip Lake, Alberta

The Chip Lake property is located 125 kilometres west of Edmonton, Alberta. Longview holds a 100% working interest in seven sections of land with Current Production of approximately 136 boe/d from the Rock Creek Formation. The field consists of vertical oil wells, vertical water injection wells and a central oil processing battery and water disposal facility. Associated natural gas is is pipelined to and compressed through third party facilities where natural gas liquids are extracted and sold. Clean oil is trucked for sale.

The Rock Creek Formation is a conventional sandstone reservoir in which 40^{o} API oil is trapped against an up-dip shale plug channel that truncates the reservoir which occurs at a depth of 1,850 metres. Pay thickness is in excess of eight metres along the axis of the reservoir and it is there and along the up-dip margin that infill drilling, potentially with a combination of vertical and horizontal wells, will be targeted after water injection has re-pressured the pool. The water injection scheme is also being evaluated for additional injector conversions for improved sweep efficiencies.

Cardium properties, West Central Alberta

The Cardium Formation properties lie in the west central Alberta basin primarily between Townships 38 and 48, Ranges 2 to 11W5. These properties consist of a variety of lands with working interests ranging between 8% and 100%. Most of the properties are non-operated with the exception of the Pembina Rose Creek Cardium Unit, which is 100% owned and operated. Current Production is approximately 413 boe/d from these properties. Longview's interests in this area also include a 1.5% working interest in the North Pembina Cardium Unit Number 1.

Pembina Rose Creek Cardium Unit

Longview has a 100% unit interest in and operates this 1,600 acre Cardium unit. The unit produces 36° API oil with Current Production for the unit of approximately 90 boe/d. The Cardium Formation in this unit consists of up to 7 metres of net pay located within the southern boundary of the main Pembina field. The unit is under active waterflood that is being evaluated for optimization opportunities. This property represents an opportunity for the application of multi-stage frac horizontal drilling and as such, 3 horizontal wells will be drilled and evaluated in 2014.

Sunset, Alberta

This property consists of three pools all of which are producing from Triassic age Montney Formation reservoirs and lies approximately 100 kilometres east of the City of Grande Prairie. Current Production from the three main pools in the Sunset area is approximately 512 boe/d.

Sunset "A"

Current Production of 332 boe/d consists of 29^{o} API crude oil and solution gas from the Montney Formation occurring at a depth of 1,450 metres. In this area, the Montney is a conventional fine grained sandstone reservoir in which crude oil has been trapped stratigraphically against cap rock overlying the up-dip sub-crop unit of the reservoir. The reservoir has an underlying water leg which provides partial pressure support. Longview has a 70% working interest, and operates the Sunset Triassic "A" Unit. The field is currently developed with mainly vertical wells drilled from central production pads. There is a 40 year production history with stable well performance and low decline. Infill drilling to 40 acre spacing in the pool commenced in 2005 and since that time 24 oil wells and five additional injection wells have been added to the pool. In the center of the field, drilling has been successfully downspaced to 20 acre spacing units. Additional injector conversions have been added and expansion of the water injection system is ongoing. In 2013, a horizontal well with multi-stage fracs was drilled on the east side of the pool and is performing as expected. As a result, additional horizontal infill wells are currently being evaluated to capture additional oil reserves.

Sunset "B"

Current Production from this Montney oil reservoir was approximately 125 boe/d. Longview has a 100% interest in this pool and owns 88% of a sour gas processing plant and gathering system with throughput capacity of 12 MMcf/d. Associated gas from Sunset "A" and from Valleyview is gathered and processed through this facility.

Valleyview

This Montney pool had Current Production of 55 boe/d and is connected to the Sunset "B" gas processing plant by a 12 kilometre pipeline with Longview holding a 93% average working interest in the pool.

The Sproule Report assigns 1.5 bcf of gross (1.4 bcf net) proved natural gas reserves and 1,668 Mbbls of gross (1,461 Mbbls net) proved crude oil and NGL reserves to Sunset/Valleyview. In addition, 8.8 bcf of gross (8.2 bcf net) probable natural gas reserves and 1,291 Mbbls of gross (1,066 Mbbls net) probable crude oil and NGL reserves have been assigned to these properties.

Duvernay and Nordegg Resource Play

Longview also ownes a 100% interest in 81,224 gross (127 net sections) acres of exploratory rights in and along the Sunset corridor, which are prospective for development in the Upper Devonian Duvernay Formation as well as the Jurassic Nordegg Formation. A stratigraphic test well was drilled at the end of 2011 which cored both the Nordegg and Duvernay intervals. Longview believes that both the Duvernay and Nordegg lands are located within the oil generating window in this area and Longview will continue to review and analyze this target to determine future exploratory activity. Longview's ownership of oil and natural gas facilities in this area is available to provide immediate processing capacity should development proceed.

Skaro/Alexis, Alberta

Skaro, Alberta

The Skaro property is located 50 kilometres northeast of Edmonton, Alberta. This is an operated property in which Longview has a 100% working interest. Current Production at Skaro was approximately 102 boe/d. Oil is gathered and processed at 100% operated facilities where clean oil is then trucked out for sale. Production in this area is 17^{o} API gravity oil which occurs at shallow depths of 900 metres. Oil is trapped in pools within a large Cretaceous age, Ellerslie Formation, channel/valley trend in which numerous multi-well oil pools have accumulated. The pools are separated by shale filled channels which provide the hydrocarbon trap and separation of pools. On the Skaro lands there are two pools, the Basal Quartz (Ellerslie) "C" Pool which is currently developed with six horizontal wells and the Basal Quartz (Ellerslie) "G" Pool which has one producing horizontal well.

The Sproule Report assigns to the Skaro area 151 Mbbls of gross (139 Mbbls net) proved crude oil and NGL reserves to this property. In addition, 52 Mbbls of gross (48 Mbbls net) probable crude oil and NGL reserves have been assigned to this property.

Alexis, Alberta

The Alexis property is located 50 kilometres northwest of Edmonton, Alberta. Longview holds a 13.966% non-operated working interest in the Alexis Banff "A" pool unit which produces slightly sour 22° API crude oil and natural gas from a siliclastic carbonate member within the Mississippian Banff Formation which is found at a depth of 1,400 metres. The pool is developed with both vertical and horizontal wells and is operating under a waterflood pressure maintenance scheme. Current production at Alexis is 68 boe/d.

The Sproule Report assigns 0.5 bcf of gross (0.4 bcf net) proved natural gas reserves and 212 Mbbls of gross (188 Mbbls net) proved crude oil and NGL reserves to the Alexis property. In addition, 0.1 bcf of gross (0.1 bcf net) probable natural gas reserves and 54 Mbbls of gross (44 Mbbls net) probable crude oil and NGL reserves have been assigned to this property.

Saskatchewan

Southeast Saskatchewan

This area consists of a number of individual properties and lands located within the Williston Sedimentary Basin in the southeast quadrant of Saskatchewan. Existing production at the major properties comes principally from the Ordovician Red River Formation, Devonian Winnipegosis Formation as well as from the Mississippian Midale, Frobisher and Bakken Formations. Current Production from this area is approximately 2,370 boe/d and is comprised mainly of low decline, high netback, light oil with an average API gravity of 30°.

Weyburn, Macoun and Pinto Areas – Midale Formation Development

The Midale Formation is a Mississippian carbonate reservoir and contains one of Canada's largest light oil pools with API gravities ranging from 32° to 40°. The Midale Formation is comprised of two distinct naturally fractured low permeability reservoirs one being a higher porosity dolomite Marly zone that overlies a lower porosity limestone Vuggy zone.

Longview has 70,118 gross undeveloped (59,075 net) acres of lands that are prospective for drilling in the Midale Formation and represents the largest opportunity base in the Southeast Saskatchewan area. Longview holds direct ownership of the mineral title in approximately 62% of the net acres.

In the Weyburn area, oil is trapped along the up-dip erosional edge of the Midale unconformity. In this area, the Vuggy zone is the main target and produces 32° API oil through a number of vertical wells. Longview’s interests in this area vary between 80% and 100%. In 2013, a horizontal well was drilled and put on production and is performing as expected. As a result, 3 additional horizontal wells are scheduled to be drilled in 2014. In addition, this pool is also being evaluated for waterflooding given that there are successful Midale Vuggy waterfloods operating in the vicinity.

In the Macoun area, oil is trapped along the up-dip edge of a Midale stratigraphic trap. In this area, the Marly zone is the main target and produces 40° API oil through a collection of both vertical and horizontal wells. Longview’s interests in this area vary between 50% and 100%. There are a number horizontal wells scheduled to be drilled in this area in 2014. This pool is also being considered for waterflooding given that there are successful Midale Marly waterfloods operating in the vicinity. This area has been a very active area for Longview in that a total of 18 horizontal wells (14 net) were drilled in last 3 years. In addition, there is also potential for increased oil recovery from the Vuggy zone and there are plans underway to evaluate this potential in the coming months.

In the Pinto area, oil is trapped along the up-dip edge of a Midale structural and stratigraphic high believed to be a shoaling event. In this area, the Vuggy zone is the main target and produces 40° API oil through a collection of both vertical and horizontal wells. Longview’s interest in this area is 100%. There are 3 horizontal wells scheduled to be drilled in this area in 2014. This pool is also being considered for waterflooding given that there are successful Midale Vuggy waterfloods operating in the vicinity. This area has been a very active area for Longview in that a total of 6 horizontal wells were drilled in last 2 years. In addition, there is also potential for increased oil recovery from the Marly zone and there are plans underway to evaluate this potential in the coming months.

The assets in this area also include 71,301 gross (56,725 net) acres of land that are prospective in the Bakken and Three Forks Sanish Formations. Longview holds direct ownership of the mineral title in approximately 65% of the net acres. There has been significant industry activity surrounding these lands targeting light oil resource plays. Drilling potential will be evaluated in these formations as information from surrounding industry activity becomes available in the public domain. Current production in these areas is approximately 1,046 boe/d.

Wapella Property

The Wapella property is located 200 kilometres east of Regina, Saskatchewan with Current Production of approximately 541 boe/d of 25º API gravity oil with an average working interest of 90%. Production is derived from the Cretaceous and Jurassic-age Shaunavon and Gravelbourg sandstone reservoirs located at a depth of 800 metres. Additional infill drilling and stepouts have been identified in and around the existing reservoirs.

Longview also has undeveloped lands that are prospective in the Bakken Formation. Significant exploration potential exists on the undeveloped land base and recent activity for Bakken target, to the east of Wapella, suggest that favorable geological potential in this horizon could extend westward onto lands owned by Longview.

The Sproule Report assigns 1,419 Mbbls of gross (1,115 Mbbls net) proved crude oil reserves in Wapella. In addition 2,175 Mbbls of gross (1,917 Mbbls net) probable crude oil and NGL reserves have been assigned to this area.

Lloydminster, Saskatchewan Area

The Eyehill and Lashburn oil properties are located east of the Saskatchewan/Alberta border within the Lloydminster heavy oil producing area. Current Production from these properties is approximately 548 boe/d derived primarily from the Cretaceous Sparky and Waseca Formations and also from the Rex, Cummings and Dina Formations. Crude oil gravities in these properties range between 12 and 20º API and are all being produced conventionally at this time.

Eyehill, Saskatchewan

The Eyehill property (100% working interest) consists of 25 oil wells with Current Production of approximately 250 boe/d producing from a 20º API Sparky Formation sandstone reservoir in which oil is trapped up-dip and laterally against cross cutting shale filled channels. The Sparky oil pool is under waterflood pressure maintenance from seven injection wells and continues to show positive production response to this injection.

Lashburn, Saskatchewan

At Lashburn where Longview holds a 60% working interest, there are two thick Waseca channels present as identified in vertical wells and on 3D seismic, one on the east side and one on the west side of the property. Current Production is approximately 298 boe/d of 12º API oil. Similar Waseca channels are being developed with SAGD (steam assisted gravity drainage) technology immediately south of the property by a major oil company and this technology is applicable at the Lashburn property. As an alternative, this property may be developed through a combination of vertical and horizontal infill drilling to increase production and enhance reserves. There are 4 vertical wells scheduled to be drilled in this area in 2014.

The Sproule report assigns 1,151 Mbbls of gross (1,006 Mbbls net) proved crude oil reserves to the properties in the Lloydminster area. In addition, 2,881 Mbbls of gross (2,689 Mbbls net) probable crude oil and NGL reserves have been assigned to this area.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2013 in which we have a working interest.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	324	198	80	62	198	167	119	108
Saskatchewan	308	245	177	152	69	2	10	8
Total[(1)(2)]	632	443	257	214	267	169	129	116

Note:

(1) Includes wells of Longview (without reduction to reflect the Longview Non-Controlling Interest).

Properties with no Attributed Reserves

The following table sets out our unproved properties as at December 31, 2013.

	Gross Acres	Net Acres
Alberta	158,887	142,089
Saskatchewan	103,296	77,096
Total[(1)]	262,183	219,185

Note:

(1) Includes developed and undeveloped land holdings of Longview (without reduction to reflect the Longview Non-Controlling Interest).

We expect that rights to explore, develop and exploit 46,441 net acres of our undeveloped land holdings will expire by December 31, 2014. The land expirations do not consider our 2014 exploitation and development program that may result in extending or eliminating such potential expirations. We closely monitor land expirations as compared to our development program with the strategy of minimizing undeveloped land expirations relating to significant identified opportunities. Development of the Corporation's properties with no attributed reserves are subject to current industry conditions and uncertainties as indicated under "*Risk Factors*" herein.

Forward Contracts

Our operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely in recent years. Such prices are primarily determined by economic, and in the case of oil prices, political factors. Supply and demand factors, as well as weather, general economic conditions, and conditions in other oil and natural gas regions of the world also impact prices. Any upward or downward movement in oil and natural gas prices could have an effect on our financial condition and capital development.

Advantage (excluding Longview) approved a hedging policy using, amongst others, costless collars and fixed price swaps to hedge up to 65% of its gross oil, NGLs and natural gas production for a maximum period of three years and 50% over the fourth year. Longview approved a hedging policy using, amongst others, costless collars and fixed price swaps to hedge up to 60% of its gross oil, NGLs and natural gas production for a maximum period of two years, and 50% over the third year. These hedging activities could expose the Corporation to losses or gains. To the extent that the Corporation engages in risk management activities related to commodity prices, it will be subject to credit risk associated with the parties with which it contracts. This credit risk will be mitigated by entering into contracts with only stable and creditworthy parties and through the frequent review of the Corporation's exposure to these entities. See "*Risk Factors*".

Advantage has the following derivatives in place:

Natural gas - AECO

Period	Average Production Hedged	Average Price AECO - $Cdn.
Q1 2014 to Q4 2014	60.2 MMcf/d	$3.81/Mcf
Q1 2015 to Q4 2015	75.8 MMcf/d	$3.90/Mcf
Q1 2016	52.1 MMcf/d	$3.88/Mcf

Longview has the following derivatives in place:

Crude oil – WTI

Period	Average Production Hedged	Average Price WTI - $Cdn.
Q1 2014 to Q4 2014	2,000 bbls/d	$94.84/bbl

Additional Information Concerning Abandonment and Reclamation Costs

We estimate the costs to abandon and reclaim all our non-producing and producing wells, gas plants, pipelines, batteries, and other facilities. No estimate of salvage value is netted against the estimated cost. Our model for estimating the amount of future abandonment and reclamation expenditures was done on an individual well and facility level. Estimated expenditures for each well and facility are base on internal estimates through consultation with our Health, Safety and Environment Department. Each well and facility are assigned an average cost for abandonment and reclamation over a 60 year period. Timing of expenditures are based on budgets and estimates of such annual activities. Facility reclamation costs are generally scheduled to begin shortly before the end of the reserve life of our associated reserves and continue beyond the reserve life under the assumption that decommissioning of plant/facilities are generally mobile assets with a long useful life.

We estimate that we will incur reclamation and abandonment costs on 942 net producing and non-producing wells and 601 net abandoned wells. The approximate net cost to abandon and reclaim all wells and facilities, discounted at 10%, totals $24.4 million ($158.3 million undiscounted), of which approximately $5.5 million are included in the estimate of future net revenue ($56.0 million undiscounted). Abandonment and reclamation costs undiscounted and expected to be paid over the next three years totals $12.7 million.

Tax Horizon

In 2013, we did not pay any income related taxes and it is expected, based on current legislation that no cash income taxes are to be paid by AOG prior to 2018. See "*Risk Factors*".

Capital Expenditures

The following tables summarize capital expenditures (including capitalized general and administrative expenses) related to our activities for the year ended December 31, 2013:

Capital Expenditures ($ thousands)[1]	**2013**
Land and seismic	55
Drilling, completions and workovers	162,703
Well equipping and facilities	26,204
Other	79
Total expenditures on property, plant and equipment	189,041
Property Acquisition – Proved Properties	-
Property Acquisition – Unproved Properties	6,977
Property dispositions	(54,855)
Exploration costs	-
Development costs	-
Total capital expenditures	$141,163

Note:

(1) Includes capital expenditures related to Longview (without reduction to reflect the Longview Non-Controlling Interest).

Exploration and Development Activities

The following table sets forth the gross and net wells in which we participated during the year ended December 31, 2013:

	Exploratory		**Development**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil wells	-	-	26	14.7	26	14.7
Gas wells	-	-	16	16	16	16
Service wells	-	-	2	1.7	2	1.7
Dry holes	-	-	1	1	1	1
Total[1]	-	-	45	33.4	45	33.4

Note:

(1) Includes wells in which Longview participated (without reduction to reflect the Longview Non-Controlling Interest).

Subject to, among other things, the availability of drilling rigs and weather that permits access to drill sites, in the first six months of 2014, we plan to drill, complete and tie-in approximately 38.3 net wells.

See "*Other Oil and Gas Information – Property Descriptions*" for a description of the Corporation's exploration and development activities.

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2014 reflected in the estimate of future net revenue disclosed in the tables contained under "*Disclosure of Reserves Data*".

	Light and Medium Oil(1)		Heavy Oil(1)		Natural Gas(1)		Natural Gas Liquids(1)		Total(1)	
	(bbls/d)		(bbls/d)		(Mcf/d)		(bbls/d)		(Boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Producing	2,970	2,543	591	500	100,603	94,696	615	493	20,944	19,319
Proved Developed Non-Producing	168	164	1	1	12,956	12,315	1	1	2,329	2,218
Proved Undeveloped	440	398	88	64	14,666	13,888	49	43	3,021	2,820
Total Proved	3,579	3,105	679	565	128,225	120,899	665	538	26,294	24,357
Total Probable	397	362	68	55	14,329	13,559	23	21	2,876	2,697
Total Proved Plus Probable[(1)]	3,976	3,466	747	620	142,553	134,458	688	558	29,170	27,054

Note:

(1) Includes Longview production (without reduction to reflect the Longview Non-Controlling Interest).

Production History

The following tables summarize certain information in respect of production, prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarter Ended 2013[(5)]				Year Ended[(5)]
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2013
Average Daily Production[(1)]					
Crude Oil (bbls/d)	4,822	4,594	4,207	4,289	4,475
Gas (Mcf/d)	27,360	26,007	24,551	23,938	25,452
NGLs (bbls/d)	1,305	772	531	522	780
Combined (boe/d)	27,360	26,007	24,551	23,938	25,452
Average Net Production Prices Received					
Crude Oil ($/bbl)	77.16	84.92	98.47	79.13	84.67
Gas ($/Mcf)	3.00	3.48	2.47	3.25	3.05
NGLs ($/bbl)	63.14	53.12	54.29	57.19	58.15
Combined ($/boe)	30.58	33.16	29.99	30.98	31.19
Gain/(Loss) on Derivatives					
Crude Oil ($/bbl)	(1.34)	(2.08)	(8.67)	(4.98)	(4.15)
Gas ($/Mcf)	0.05	(0.11)	0.15	0.16	0.06
Combined ($/boe)	0.01	(0.89)	(0.73)	(0.09)	(0.42)
Royalties Paid					
Crude Oil ($/bbl)	12.86	13.59	17.12	17.62	15.21
Gas ($/Mcf)	0.07	0.17	0.08	0.02	0.09
NGLs ($/bbl)	16.88	23.27	15.76	15.48	18.02
Combined ($/boe)	3.39	3.91	3.69	3.60	3.64
Operating Expenses[(2)(3)]					
Crude oil ($/bbl)	19.55	21.27	21.67	23.31	21.41
Natural gas ($/Mcf)	1.00	0.63	0.45	0.42	0.63
NGLs ($/bbl)	10.19	12.05	14.44	14.15	12.04
Combined ($/boe)	8.59	7.11	6.21	6.50	7.14
Netback Received[(4)]					
Crude Oil ($/bbl)	43.41	47.98	51.01	33.22	43.90
Gas ($/Mcf)	1.98	2.57	2.09	2.97	2.39
NGLs ($/bbl)	36.07	17.80	24.09	27.56	28.09
Combined ($/boe)	18.61	21.25	19.36	20.79	19.99

Notes:

(1) Before deduction of royalties.

(2) This figure includes all field operating expenses.
(3) We do not record operating expenses on a commodity basis. Information in respect of operating expenses for crude oil and NGLs ($/bbl) and natural gas ($/Mcf) has been determined by allocating expenses on a well by well basis based upon the relative volume of production of crude oil and NGLs and natural gas.
(4) Information in respect of netbacks received for crude oil & NGLs ($/bbl) and natural gas ($/Mcf) is calculated using operating expense figures for crude oil and NGLs ($/bbl) and natural gas ($/Mcf), which figures have been estimated. See note (3) above.
(5) Includes Longview (without reduction to reflect the Longview Non-Controlling Interest).

The following table indicates our approximate average daily production from our important fields for the year ended December 31, 2013:

Properties	**Natural Gas (Mcf/d)**	**NGLs (bbls/d)**	**Crude Oil (bbls/d)**	**Total (boe/d)**
Alberta				
Glacier	107,715	-	63	18,016
Nevis	3,512	307	514	1,406
Red Deer	349	8	1	67
Westerose	719	74	219	413
Skaro/Alexis	138	-	138	161
Sunset	923	33	325	512
	113,356	422	1,260	20,575
Saskatchewan				
Steelman Area	150	2	2,342	2,369
Sask Heavy Oil Area	138	-	526	549
	288	2	2,868	2,918
Other	1,119	98	161	445
Total	114,763	522	4,289	23,938

Note:

(1) Includes Longview (without reduction to reflect the Longview Non-Controlling Interest).

Material Changes since December 31, 2013

Longview completed the 2014 Secondary Offering on February 28, 2014. As a result, as at February 28, 2014, Advantage does not own or control or direct, directly or indirectly, any common shares of Longview and Longview is no longer a subsidiary of Advantage. See "*General Development of the Business - Recent Developments*".

Reserves

The tables below represent a summary of reserves estimated in the Sproule Advantage Report and attributable to Advantage (without Longview) and a summary of the net present value (before tax) of such reserves, all as at December 31, 2013. All reserves stated herein are based on forecast prices and costs.

SUMMARY OF OIL AND GAS RESERVES
as at December 31, 2013
FORECAST PRICES AND COSTS

	RESERVES			
	LIGHT AND MEDIUM OIL		**HEAVY OIL**	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED				
Developed Producing	6.0	5.2	-	-
Developed Non-Producing	-	-	-	-
Undeveloped	-	-	-	-
TOTAL PROVED	6.0	5.2	-	-
PROBABLE	0.9	0.8	-	-

TOTAL PROVED PLUS PROBABLE	7.0	6.0	-	-

	RESERVES			
	NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED				
Developed Producing	205,253	193,466	758.3	568.4
Developed Non-Producing	27,648	26,166	243.4	188.1
Undeveloped	759,424	715,899	6,084.0	4,966.3
TOTAL PROVED	992,325	935,531	7,085.7	5,722.8
PROBABLE	626,509	565,005	5,948.6	4,383.3
TOTAL PROVED PLUS PROBABLE	1,618,833	1,500,536	13,034.3	10,106.1

	RESERVES	
	TOTAL OIL EQUIVALENT	
RESERVES CATEGORY	**Gross (Mboe)**	**Net (Mboe)**
PROVED		
Developed Producing	34,973.2	32,817.9
Developed Non-Producing	4,851.3	4,549.0
Undeveloped	132,654.7	124,282.6
TOTAL PROVED	172,479.2	161,649.8
PROBABLE	110,367.7	98,551.7
TOTAL PROVED PLUS PROBABLE	282,846.9	260,201.5

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as at December 31, 2013

FORECAST PRICES AND COSTS

	Before Income Tax Discounted at (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/ year(1)
RESERVES CATEGORY	**0% ($000's)**	**5% ($000's)**	**10% ($000's)**	**15% ($000's)**	**20% ($000's)**	**0% ($000's)**	**5% ($000's)**	**10% ($000's)**	**15% ($000's)**	**20% ($000's)**	**($/boe)**
PROVED											
Developed Producing	786,135	577,524	465,720	395,466	346,829	786,135	577,524	465,720	395,466	346,829	14.19
Developed Non-Producing	117,613	86,285	69,208	58,238	50,512	117,613	86,285	69,208	58,238	50,512	15.21
Undeveloped	2,604,491	1,267,819	692,264	398,953	232,830	2,007,655	988,694	542,083	310,987	178,258	5.57
TOTAL PROVED	3,508,239	1,931,629	1,227,192	852,658	630,171	2,911,403	1,652,503	1,077,011	764,691	575,599	7.59
PROBABLE	3,140,500	1,509,093	891,548	591,703	422,891	2,356,640	1,133,324	673,306	451,337	326,863	9.05
TOTAL PROVED PLUS PROBABLE	6,648,738	3,440,722	2,118,740	1,444,360	1,053,062	5,268,042	2,785,827	1,750,317	1,216,028	902,461	8.14

Note:

(1) The unit values are based on net reserve volumes.

Oil and Gas Wells

The following table sets forth the number and status of wells as at December 31, 2013 in which Advantage (without Longview) had a working interest.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	-	-	-	-	132	117	52	51
Saskatchewan	-	-	-	-	-	-	-	-
Total	-	-	-	-	132	117	52	51

Properties with no Attributed Reserves

The following table sets out the unproved properties of Advantage (without Longview) as at December 31, 2013.

	Gross Acres	Net Acres
Alberta	58,952	50,237
Total(1)	58,952	50,237

We expect that rights to explore, develop and exploit 5,760 net acres of our undeveloped land holdings will expire by December 31, 2014. The land expirations do not consider our 2014 exploitation and development program that may result in extending or eliminating such potential expirations. We closely monitor land expirations as compared to our development program with the strategy of minimizing undeveloped land expirations relating to significant identified opportunities. Development of the Corporation's properties with no attributed reserves are subject to current industry conditions and uncertainties as indicated under "*Risk Factors*" herein.

Abandonment and Reclamation Costs

We estimate that Advantage will incur reclamation and abandonment costs on 183 net producing and non-producing wells and 327 net abandoned wells. The approximate net cost to abandon and reclaim all wells and facilities, discounted at 10%, totals $15.3 million ($46.3 million undiscounted), of which approximately $0.7 million are included in the estimate of future net revenue ($31.9 million undiscounted). Abandonment and reclamation costs undiscounted and expected to be paid over the next three years totals $10.9 million.

Capital Expenditures

The following tables summarize capital expenditures (including capitalized general and administrative expenses) related to Advantage's activities (without Longview) for the year ended December 31, 2013:

Capital Expenditures ($ thousands)	2013
Land and seismic	$55
Drilling, completions and workovers	135,507
Well equipping and facilities	12,977
Other	-
Total expenditures on property, plant and equipment	148,539
Property Acquisition – Proved Properties	-
Property Acquisition – Unproved Properties	6,831
Property dispositions	(52,903)
Exploration costs	-
Development costs	-
Total capital expenditures	$102,467

Exploration and Development Activities

The following table sets forth the gross and net wells in which Advantage (without Longview) participated during the year ended December 31, 2013:

	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	-	-	7	.3	7	.3
Gas wells	-	-	16	16	16	16
Service wells	-	-	1	1	1	1
Dry holes	-	-	-	-	-	-
Total	-	-	24	17.3	24	17.3

Subject to, among other things, the availability of drilling rigs and weather that permits access to drill sites, in the first six months of 2014, Advantage plans to drill, complete and tie-in approximately 16 net wells.

See "*Other Oil and Gas Information – Property Descriptions*" for a description of the Corporation's exploration and development activities.

Production Estimates

The following table sets out the volume of production estimated for Advantage (without Longview) for the year ended December 31, 2014 reflected in the estimate of future net revenue disclosed in the tables above.

	Light and Medium Oil (bbls/d)		Heavy Oil (bbls/d)		Natural Gas (Mcf/d)		Natural Gas Liquids (bbls/d)		Total (Boe/d)	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved Producing	2	1	-	-	94,384	89,121	184	174	15,917	15,029
Proved Developed Non-Producing	-	-	-	-	12,945	12,299	-	-	2,158	2,050
Proved Undeveloped	-	-	-	-	14,090	13,386	-	-	2,348	2,231
Total Proved	2	1	-	-	121,419	114,805	184	174	20,423	19,310
Total Probable	-	-	-	-	14,211	13,452	12	11	2,380	2,253
Total Proved Plus Probable	2	1	-	-	135,630	128,258	196	185	22,803	21,562

Production History

The following tables summarize certain information in respect of production, prices received, royalties paid, operating expenses and resulting netback for Advantage (without Longview) for the periods indicated below:

	Quarter Ended 2013				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2013
Average Daily Production[(1)]					
Crude Oil (bbls/d)	564	292	85	63	249
Gas (Mcf/d)	119,692	116,469	111,518	108,260	113,947
NGLs (bbls/d)	744	262	20	16	258
Combined (boe/d)	21,257	19,966	18,691	18,122	19,498
Average Net Production Prices Received					
Crude Oil ($/bbl)	82.02	85.87	97.77	77.79	84.23
Gas ($/Mcf)	2.98	3.47	2.46	3.21	3.03
NGLs ($/bbl)	70.46	59.10	83.70	73.87	67.89
Combined ($/boe)	21.42	22.25	15.21	19.52	19.68

	Quarter Ended 2013				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2013**
Gain/(Loss) on Derivatives					
Crude Oil ($/bbl)	0.32	-	-	-	0.17
Gas ($/Mcf)	0.06	(0.12)	0.17	0.18	0.07
Combined ($/boe)	0.33	(0.68)	0.99	1.05	0.40
Royalties Paid					
Crude Oil ($/bbl)	10.04	18.27	5.31	0.59	11.45
Gas ($/Mcf)	0.02	0.15	0.11	0.13	0.10
NGLs ($/bbl)	16.48	35.32	43.11	23.15	21.86
Combined ($/boe)	0.97	1.58	0.75	0.91	1.06
Operating Expenses(2)(3)					
Crude oil ($/bbl)	4.59	2.82	1.58	1.67	3.65
Natural gas ($/Mcf)	0.85	0.45	0.29	0.28	0.47
NGLs ($/bbl)	5.36	2.71	1.08	1.07	4.57
Combined ($/boe)	5.18	2.67	1.73	1.66	2.88
Netback Received(4)					
Crude Oil ($/bbl)	67.71	64.78	90.88	75.53	69.30
Gas ($/Mcf)	2.17	2.75	2.23	2.80	2.53
NGLs ($/bbl)	48.62	21.07	39.51	49.65	41.46
Combined ($/boe)	15.60	17.32	13.72	18.00	16.14

Notes:

(1) Before deduction of royalties.
(2) This figure includes all field operating expenses.
(3) We do not record operating expenses on a commodity basis. Information in respect of operating expenses for crude oil and NGLs ($/bbl) and natural gas ($/Mcf) has been determined by allocating expenses on a well by well basis based upon the relative volume of production of crude oil and NGLs and natural gas.
(4) Information in respect of netbacks received for crude oil & NGLs ($/bbl) and natural gas ($/Mcf) is calculated using operating expense figures for crude oil and NGLs ($/bbl) and natural gas ($/Mcf), which figures have been estimated. See note (3) above.

Marketing

Our crude oil and natural gas production is primarily sold through marketing companies at current market prices. Crude oil contracts are generally for less than a year and are cancellable on 30 days notice and natural gas contracts are generally for one year and are cancellable on 60 days notice. NGL contracts are renegotiated annually and the contracts run for one year and are not cancellable for that term. None of our natural gas production is sold to aggregators who accumulate production from various producers and market the gas on behalf of the group. Such contracts are reserve specific and continue for the life of production from the specified reserves.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing hedging programs, as deemed necessary, to lock-in netbacks on production volumes. See "*Other Oil and Gas Information – Forward Contracts*" for our current hedging program.

Environmental Considerations

We are pro-active in our approach to environmental concerns. Procedures are in place to ensure that the utmost care is taken in the day-to-day management of our oil and gas properties. All government regulations and procedures are followed in strict adherence to the law. We believe in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs to us. Our Environmental Management System is continuously updated and meets the Canadian Association of Petroleum Producers ("**CAPP**") Environmental Management Guidelines.

Health, Safety and Environmental

AOG is committed to a comprehensive and effective health, safety and environmental program that meets or exceeds regulatory and corporate requirements.

AOG participates in the Certificate of Recognition ("**COR**") Safety Program and has received certification for the last three years. The COR Health and Safety Auditing and the COR Safety Program requires commitment to continuous improvement in the environment, health and safety management practices including sound planning and implementation. The program is audited externally every 3 years and internally every other year. The program ensures open communication and measured performance to maintain such program.

Management, employees and all contractors are responsible and accountable for the overall health, safety and environmental program. AOG will operate in compliance with all applicable regulations and will ensure all staff and contractors employ sound practices to protect the environment and to ensure employee and public health and safety.

In 2013 the Corporation met the AER Enhanced Production Audit Program with a compliance rating for Glacier of 100% satisfactory, which exceeds the industry average, and Advantage's incident ratings in 2013 were significantly below industry averages. In addition, a total of 10 reclamation certificates were received by Advantage in 2013 (four of these were on properties that were subsequently sold) and Advantage's spill volumes in the last two years were negligible.

The Corporation maintains and will maintain a safe and environmentally responsible work place and provide training, equipment and procedures to all individuals in adhering to our policies. The Corporation will also solicit and take into consideration input from our neighbours, communities and other stakeholders in regard to protecting people and the environment.

Competitive Conditions

We are a member of the petroleum industry, which is highly competitive at all levels. We compete with other companies for all of our business inputs, including exploitation and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. See "*Risk Factors*".

We strive to be competitive by maintaining a strong financial condition and by utilizing current technologies to enhance exploitation, development and operational activities.

DIRECTORS AND OFFICERS

The following table sets forth the name, place of residence, date first elected as a director of AOG and positions for each of the directors and officers of AOG as at the date hereof, together with their principal occupations during the last five years.

Name, Province and Country of Residence	Position Held and Period Served as a Director or Officer(4)(5)	Principal Occupations During Past Five Years
Andy J. Mah Alberta, Canada	President since April 21, 2011, Chief Executive Officer since January 27, 2009 and a Director since June 23, 2006	President since April 21, 2011. Chief Executive Officer since January 27, 2009. President and Chief Operating Officer from June 23, 2006 to January 27, 2009. Chief Operating Officer of Longview from December 15, 2010 to November 7, 2013. Prior thereto, President of Ketch Resources Ltd. from October 2005 to June 2006. Chief Operating Officer of Ketch Resources Ltd. from January 2005 to September 2005. Prior thereto, Executive Officer and Vice President, Engineering and Operations of Northrock Resources Ltd. from August 1998 to January 2005.

Name, Province and Country of Residence	Position Held and Period Served as a Director or Officer[(4)(5)]	Principal Occupations During Past Five Years
Ronald A. McIntosh[(1)(2)(3)(7)] Alberta, Canada	Director since September 25, 1998[(6)] Interim Chairman since February 4, 2014	Chairman of North American Energy Partners Inc., a publicly traded corporation and a director of Fortaleza Energy Inc., previously known as Alvopetro Inc., formerly named Fortress Energy Inc. Mr. McIntosh has extensive experience in the energy business. His previous roles included President and Chief Executive Officer of Navigo Energy, Chief Operating Officer of Gulf Canada, Vice President Exploration and International of PetroCanada and Chief Operating Officer of Amerada Hess Canada.
Stephen E. Balog[(1)(2)(3)] Alberta, Canada	Director since August 16, 2007	Principal of Alconsult International Ltd. and President, West Butte Management Inc., private consulting companies that provide technical and business advisory services to oil and gas operators, and director of Questfire Energy Corp. Prior thereto, President and Chief Operating Officer and a Director of Tasman Exploration Ltd. from 2001 to June,2007. Mr. Balog has extensive oil and gas industry experience and was a key contributor to the development and use of the Canadian Oil & Gas Evaluation Handbook as an industry standard for reserves evaluation. He served on the Petroleum Advisory Committee, Alberta Securities Commission from 2009-2011 and has a Bachelor of Science, Chemical Engineering.
Paul Haggis[(1)(2)(3)] Alberta, Canada	Director since November 7, 2008	Mr. Haggis' was President and Chief Executive Officer of Ontario Municipal Employees Retirement System (OMERS) from September 2003 to March 2007, Interim Chief Executive Officer of the Public Sector Pension Investment Board (PSPIB) during 2003 and Executive Vice-President, Development and Chief Credit Officer of Manulife Financial in 2002. Mr. Haggis has extensive financial markets and public board experience having served on the Board of Directors of Canadian Tire Bank until March 30, 2012. He was a director and Chair of the Investment Committee of the Insurance Corporation of British Columbia and currently serves as an advisor to the committee. He was also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund, a member of the Board of UBC Investment Management Inc. and a Chairman of Alberta Enterprise Corp., and Chairman of Canadian Pacific Railway. Mr. Haggis holds a Bachelor of Arts degree from the University of Western Ontario and is certified as a Chartered Director through the Directors College at McMaster University.
Craig Blackwood Alberta, Canada	Vice President, Finance since January 27, 2009 and Chief Financial Officer since August 1, 2013	Chief Financial Officer of AOG since August 1, 2013. Vice President, Finance of AOG since January 27, 2009. Chief Financial Officer of Longview from March 4, 2010 to February 4, 2014. Mr. Blackwood is a Chartered Accountant and was the Director of Finance of AOG from November 2004 to January 27, 2009.
Neil Bokenfohr Alberta, Canada	Senior Vice President	Senior Vice President since March 27, 2014. Vice-President, Exploitation of AOG from June 23, 2006 to March 27, 2014. Vice-President, Exploitation of Longview from May 13, 2011 to November 7, 2013. Prior thereto, Vice President Exploitation and Operations of Ketch Resources Ltd. from January 2005 to June 2006; Vice President, Engineering of Bear Creek Energy Ltd. (and Crossfield Gas Corp. prior thereto) from March 2002 to January 2005. Prior thereto, Director of Exploitation for Calpine Canada Natural Gas Company from December 2000 to March 2002.
Jay P. Reid Alberta, Canada	Corporate Secretary	Partner at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 1990. He has served as a director or officer of a number of publicly listed issuers and currently serves as a Director of Madalena Ventures Inc. and as Corporate Secretary for Pinecrest Energy Inc., and Longview Oil Corp. in addition to being a Director or Corporate Secretary for five private issuers.

Notes:

(1) Member of the Audit Committee.
(2) Member of the Human Resources, Compensation and Corporate Governance Committee.
(3) Member of the Independent Reserve Evaluation Committee.
(4) AOG does not have an executive committee of the Board.
(5) AOG's directors shall hold office until the next annual general meeting of Shareholders or until each director's successor is appointed or elected pursuant to the ABCA.

(6) The period of time served by Ronald A. McIntosh as a director of AOG includes the period of time served as a director of Search prior to the Amalgamation, where applicable. Mr. McIntosh was appointed a director of post-Reorganization Search on May 24, 2001.

(7) Mr. McIntosh is a director of Fortress Energy Inc. ("**Fortress**"). On March 2, 2011, the Court of Queen's Bench of Alberta granted an order (the "**Order**") under the *Companies' Creditors Arrangement Act* (Canada) ("**CCAA**") staying all claims and actions against Fortress and its assets and allowing Fortress to prepare a plan of arrangement for its creditors if necessary. Fortress took such step in order to enable Fortress to challenge a reassessment issued by the Canada Revenue Agency ("**CRA**"). As a result of the reassessment, if Fortress had not taken any action, it would have been compelled to immediately remit one half of the reassessment to the CRA and Fortress did not have the necessary liquid funds to remit, although Fortress had assets in excess of its liabilities with sufficient liquid assets to pay all other liabilities and trade payables. Fortress believed that the CRA's position was not sustainable and vigorously disputed the CRA's claim. Fortress filed a Notice of Objection to the reassessment and on October 20, 2011 announced that its Notice of Objection was successful, CRA having confirmed there were no taxes payable. As the CRA claim had been vacated and no taxes or penalties were owing Fortress no longer required the protection of the Order under the CCAA and on October 28,2011 the Order was removed. On March 3, 2011 the TSX suspended trading in the securities of Fortress due to Fortress having been granted a stay under the CCAA. In addition the securities regulatory authorities in Alberta, Ontario and Quebec issued a cease trade order with respect to Fortress for failure to file its annual financial statements for the year ended December 31, 2010 by March 31, 2011. The delay in filing was due to Fortress being granted the CCAA order on March 2, 2011 and the resulting additional time required by its auditors to deliver their audit opinion. The required financial statements and other continuous disclosure documents were filed on April 29, 2011 and the cease trade order was subsequently removed. On September 1, 2010 Fortress closed the sale of substantially all of its oil and gas assets. As a result of the sale Fortress was delisted from the TSX on March 30, 2011 as it no longer met minimum listing requirements. Fortress was renamed Alvopetro Inc. on November 24, 2012. Alvopetro Inc. was renamed Fortaleza Energy Inc. in November 2013.

(8) As at December 31, 2013, Mr. Steven Sharpe was a director of the Corporation and resigned as a director on January 30, 2014. Mr. Sharpe is the Interim Chief Executive Officer and a director of Longview and Managing Director, The EmBeSa Corporation, a private consultancy dealing primarily with corporate restructuring, business strategy and crisis management. Mr. Sharpe was a director of Advantage from 2001 to January 31, 2014. From October 2009 to March 2010, Mr. Sharpe was Chairman and Chief Executive Officer of Prime Restaurants Royalty Income Fund. Until July, 2009, he was Senior Advisor to Blair Franklin Capital Partners, Inc., a Toronto-based investment bank which he co-founded in May, 2003. Prior to that, Mr. Sharpe was Managing Partner of Blair Franklin, from its inception.

(9) Mr. Patrick J. Cairns was the Senior Vice President of the Corporation during the year-ended December 31, 2013 and resigned on December 31, 2013. Mr. Cairns has been the Senior Vice President of Longview since May 13, 2011 and was Senior Vice President of Advantage from June 2001 to December 31, 2013. Prior thereto, Mr. Cairns was Vice President, Evaluations with the Enerplus Group of Companies, which companies specialized in the management of oil and gas income funds and royalty trusts.

As at March 27, 2014 the directors and executive officers of AOG, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 1,454,629 Common Shares, or approximately 1% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as disclosed above:

(a) no director or executive officer of AOG has, within the last ten years prior to the date of this annual information form, been a director, chief executive officer or chief financial officer of any issuer (including AOG) that, (i) while the person 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 company access to any exemption under securities legislation, that was in effect for a period of more than thirty (30) consecutive days; or (ii) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than thirty (30) consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer;

(b) no director or executive officer of AOG or security holder holding a sufficient number of securities of AOG to affect materially the control of AOG is, as at the date of this annual information form, or has, within the last ten years prior to the date of this annual information form, been a director or executive officer of any company (including AOG) 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;

(c) no director or executive officer of AOG or securityholder holding a sufficient number of securities of AOG to affect materially the control of AOG 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; and

(d) no director or executive officer of AOG or securityholder holding a sufficient number of securities of AOG to affect materially the control of AOG 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

The directors and officers of AOG may, from time to time, be involved in the business and operations of other issuers, in which case a conflict may arise. The ABCA provides that in the event a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the ABCA. To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

As at March 27, 2014, other than as disclosed herein, the Corporation was not aware of any existing or potential material conflicts of interest between the Corporation and a subsidiary of the Corporation and a director or officer of the Corporation or of a subsidiary of the Corporation. During the year ended December 31, 2013, certain officers and directors of the Corporation also formed part of the management of Longview including Craig Blackwood, the former Chief Financial Officer of Longview, Andy Mah, the former Chief Operating Officer of Longview, Patrick Cairns, the Senior Vice President of Longview, Neil Bokenfohr, the former Vice President, Exploitation of Longview, Jay P. Reid, the Corporate Secretary of Longview, and Steven Sharpe, a former director of the Corporation and the Interim Chief Executive Officer and a director of Longview. As a result, there was the potential for these individuals to encounter conflicts of interest in the event that the interests of the Corporation and Longview diverge. The Technical Services Agreement was terminated in February, 2014. See "*General Development of the Business – Recent Developments*" and "*Interest of Management and Others in Material Transactions*".

DIVIDEND POLICY

Dividend Policy of the Corporation

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

Dividend Policy of Longview

Longview has established a policy of declaring regular monthly cash dividends since the completion of the Longview Offering and the Longview Transaction. The payment and the amount of dividends declared in any month is subject to the discretion of the board of directors of Longview and will depend on the board of director's assessment of Longview's outlook for growth, capital expenditure requirements, funds from operations, potential acquisition opportunities, debt position and other conditions that the board of directors of Longview may consider relevant at such future time, including applicable restrictions that may be imposed under Longview's credit facilities and on the ability of Longview to pay dividends upon the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. The amount of future cash dividends, if any, may also 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.

The following is a summary of the dividends declared and paid by Longview for the three most recently completed financial years.

For the 2011 Period Ended	**Dividend per Common Share**	**Payment Date**
May 31	$0.05	June 15, 2011
June 30	$0.05	July 15, 2011
July 31	$0.05	August 15, 2011
August 31	$0.05	September 15, 2011
September 30	$0.05	October 17, 2011
October 31	$0.05	November 17, 2011
November 30	$0.05	December 15, 2011
December 31	$0.05	January 16, 2012
Total:	$0.40	

For the 2012 Period Ended	**Dividend per Common Share**	**Payment Date**
January 31	$0.05	February 15, 2012
February 29	$0.05	March 15, 2012
March 31	$0.05	April 16, 2012
April 30	$0.05	May 15, 2012
May 31	$0.05	June 15, 2012
June 30	$0.05	July 16, 2012
July 31	$0.05	August 15, 2012
August 31	$0.05	September 17, 2012
September 30	$0.05	October 15, 2012
October 31	$0.05	November 15, 2012
November 30	$0.05	December 17, 2012
December 31	$0.05	January 15, 2013
Total:	$0.60	

For the 2013 Period Ended	**Dividend per Common Share**	**Payment Date**
2013		
January 31	$0.05	February 15, 2013
February 28	$0.05	March 15, 2013
March 28	$0.05	April 15, 2013
April 30	$0.05	May 15, 2013
May 31	$0.05	June 17, 2013
June 28	$0.05	July 15, 2013
July 31	$0.05	August 15, 2013
August 30	$0.05	September 16, 2013
September 30	$0.05	October 15, 2013
October 31	$0.05	November 15, 2013
November 30	$0.05	December 16
December 31	$0.04	January 15, 2014
	$0.59	

DESCRIPTION OF THE CORPORATION'S SECURITIES

Share Capital

The Corporation is authorized to issue an unlimited number of Common Shares, non-voting shares, preferred shares and exchangeable shares. As of December 31, 2013, there were 168,382,838 Common Shares issued and outstanding and there were no non-voting shares, preferred shares or exchangeable shares issued and outstanding.

The following is a description of the rights attaching to the Common Shares, non-voting shares and the preferred shares.

Common Shares

Each Common Share entitles its holder to receive notice of and to attend all meetings of the shareholders of AOG and to one vote at such meetings. The holders of Common Shares are, at the discretion of the AOG Board of Directors and subject to applicable legal restrictions, entitled to receive any dividends declared by the AOG Board of Directors on the Common Shares. The holders of Common Shares are entitled to share equally in any distribution of the assets of AOG upon the liquidation, dissolution, bankruptcy or winding-up of AOG or other distribution of its assets among its shareholders for the purpose of winding-up its affairs. Such participation is subject to the rights, privileges, restrictions and conditions attaching to any instruments having priority over the Common Shares.

Non-Voting Shares

The non-voting shares have identical rights to the Common Shares except that holders of non-voting shares are not generally entitled to receive notice of or attend at meetings of shareholders of AOG or to vote their shares at such meetings.

Preferred Shares

The preferred shares may be issued, from time to time, in one or more series, each series consisting of such number of preferred shares as determined by the AOG Board of Directors, who may also fix the designations, rights, privileges, restrictions and conditions attached to the shares of each series of preferred shares. No preferred shares are presently issued and outstanding. The preferred shares of each series shall, with respect to payment of dividends and distributions of assets in the event of liquidation, dissolution or winding-up of AOG, whether voluntary or involuntary, or any other distribution of the assets of AOG among its shareholders for the purpose of winding-up its affairs, rank on a parity with the preferred shares of every other series and shall be entitled to preference over the Common Shares and the shares of any other class ranking junior to the preferred shares.

5.00% Debentures

The 5.00% Debentures pay interest semi-annually and are convertible at the option of the holder into Common Shares at the conversion price per Common Share noted below plus accrued and unpaid interest. The details of the 5.00% Debentures including the balance outstanding as at December 31, 2013 are as follows:

	5.00%
Trading symbol	AAV.DB.H
Issue date	Dec. 31, 2009
Maturity date	Jan. 30, 2015
Conversion price	$8.60
Outstanding	$86,250,000

The 5.00% Debentures are redeemable prior to their maturity date, at the option of the Corporation, upon providing appropriate days advance notification as per the terms of the debenture indenture. The redemption price for the 5.00% Debentures is $1,000, plus accrued and unpaid interest, and are redeemable after January 31, 2013 and on or before January 30, 2015, provided that the Current Market Price of the Common Shares exceeds 125% of conversion price noted above.

PRICE RANGE AND TRADING VOLUME OF SECURITIES

Common Shares

The Common Shares are listed and trade on the TSX and the NYSE and commenced trading under the symbol "AAV" following the completion of the Trust Conversion on July 9, 2009. The following table sets forth the trading history of the Common Shares for the periods indicated.

Period	High	Low	Volume
	($)	($)	
TSX Trading			
2013			
January	3.32	2.88	9,982,210
February	3.20	2.84	13,931,715
March	3.78	3.06	11,634,253
April	4.08	3.51	20,446,407
May	4.68	3.73	11,605,371
June	4.55	4.03	12,634,058
July	4.48	3.55	6,871,954
August	3.99	3.56	3,531,860
September	4.14	3.66	2,869,303
October	4.27	3.87	3,142,365
November	4.33	3.88	4,955,607
December	4.77	4.25	4,484,220
2014			
January	4.93	4.41	3,733,590
February	4.62	3.84	17,534,261
March (1 to 27)	5.08	4.29	10,329,256
NYSE Trading (U.S.$)			
2013			
January	3.37	2.89	4,779,964
February	3.16	2.79	10,808,113
March	3.72	2.97	9,102,283
April	4.02	3.46	9,015,606
May	4.51	3.69	9,048,967
June	4.48	3.83	5,784,386
July	4.33	3.45	5,729,727
August	3.86	3.39	4,317,910
September	3.99	3.55	2,397,597
October	4.13	3.71	3,129,845
November	4.11	3.72	3,738,493
December	4.47	3.99	2,730,252
2014			
January	4.57	4.03	2,241,928
February	4.18	3.47	2,773,319
March (1 to 27)	4.55	3.85	3,759,137

5.00% Debentures

The 5.00% Debentures are listed for trading on the TSX under the symbol "AAV.DB.H". The following table sets forth the high and low trading prices and the aggregate trading volume of the 5.00% Debentures as reported by the TSX for the period indicated.

Period	High	Low	Volume
	($)	**($)**	
2013			
January	99.80	99.40	21,100
February	99.80	99.10	37,800
March	99.90	99.20	53,440
April	99.80	99.10	58,941
May	101.00	99.30	30,310
June	100.70	100.20	13,910
July	100.40	99.40	37,584

Period	High	Low	Volume
	($)	($)	
August	100.00	99.60	16,610
September	100.40	99.70	93,750
October	100.80	100.00	9,960
November	101.00	100.30	30,630
December	100.90	100.50	13,870
2014			
January	101.00	100.50	9,110
February	101.00	100.50	22,780
March (1 to 27)	101.20	100.76	16,740

Prior Sales

During the year ended December 31, 2013, the Corporation granted 3,804,675 stock options with a weighted average exercise price of $3.69.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTIONS ON TRANSFER

There are presently no AOG securities held in escrow or subject to contractual restrictions on transfer.

LEGAL PROCEEDINGS

There are no outstanding legal proceedings and Advantage and its subsidiaries were not involved in any legal proceedings during the year ended December 31, 2013, which involved claims in excess of 10% of the Corporation's current asset value and to which Advantage or its subsidiaries were a party or in respect of which any of its properties are subject, nor are there any such proceedings known to be contemplated.

REGULATORY ACTIONS

During the year ended December 31, 2013 there were: (i) no penalties or sanctions imposed against AOG or its subsidiaries by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against AOG or its subsidiaries that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements AOG or its subsidiaries entered into before a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed below, there were no material interests, direct or indirect, of directors and executive officers of AOG or its subsidiaries or nominees for director of AOG or its subsidiaries, any Shareholder who beneficially owns or directs or controls more than 10% of the Common Shares or any known associate or affiliate of such persons in any transaction during the year ended December 31, 2013 or in any proposed transaction which has materially affected or would materially affect AOG or its subsidiaries.

Steven Sharpe, a director of AOG during the year ended December 31, 2013, is the Interim Chief Executive Officer and a director of Longview. In addition, concurrent with closing of the Longview Offering, AOG entered into the TSA pursuant to which AOG provided the necessary personnel and technical services to manage Longview's business, until the termination of the TSA in February, 2014. Craig Blackwood (Chief Financial Officer), Andy Mah (Chief Operating Officer) and Neil Bokenfohr (Vice President, Exploitation), each of whom are executive officers of AOG were also officers of Longview during the year ended December 31, 2013. The officers of Longview provided services to Longview under the TSA but remained as employees of Advantage. See "*General Development of the Business – 2011*".

MATERIAL CONTRACTS

Material Contracts of AOG

Except for contracts entered into by us in the ordinary course of business or otherwise disclosed herein, the only agreement which is material to AOG is the Credit Facility, a copy of which is available at www.sedar.com. See "*General Development of the Business – Three Year History*".

Material Contracts of Longview

Except for contracts entered into in the ordinary course of business the only agreements which were material to Longview as at December 31, 2013, were the agreement for the Longview Credit Facility, the TSA and the registration rights agreement between AOG and Longview (the "**Registration Rights Agreement**"), copies of which agreements are available on Longview's SEDAR profile at www.sedar.com and the terms of which are summarized below. As of the date hereof, except for contracts entered into by Longview in the ordinary course of business or otherwise disclosed herein, the only agreement which is material to Longview is the agreement for the Longview credit facility.

Longview Credit Facilities

In connection with the Longview Transaction, on April 14, 2011, Longview entered into a credit agreement with a syndicate of financial lenders for an extendible revolving credit facility in the maximum principal amount of $180 million as well as an operating credit agreement with a Canadian financial institution in the maximum principal amount of $20 million. The Longview Credit Facilities are collateralized by a floating charge demand debenture of $1 billion over Longview's assets. Various borrowing options are available under the Longview Credit Facilities, including prime rate loans, bankers' acceptances, U.S. base rate loans and LIBOR loans. The amounts available to Longview from time to time under the Longview Credit Facilities are based upon the borrowing base determined by the financial lenders which is re-determined by the lenders on an annual basis after the receipt of the independent engineering report and such other information as required by the lenders. The borrowing base constitutes a revolving facility for a 364 day term which is extendible for a further 364 day revolving period, at the option of the lenders.

Technical Services Agreement

Longview entered into the Technical Services Agreement with Advantage on April 14, 2011. Under the Technical Services Agreement, Advantage provided the necessary personnel and technical services to manage Longview's business and Longview reimbursed Advantage on a monthly basis for its share of administration charges equal to: (i) its proportionate share of Advantage's general and administrative costs, based upon its level of oil and natural gas production relative to the combined level of oil and natural gas production for Advantage and Longview but such general and administrative costs did not include direct costs attributable to Advantage, including, but not limited to, fees payable to the board of directors of Advantage, and fees associated with Advantage being a public company (including, but not limited to, expenses associated with ongoing financial reporting and disclosure, listing fees, legal fees, audit fees and costs related to ongoing investor relations and annual meetings); plus (ii) direct general and administrative costs for engineering, acquisition, legal and other professional services; less (iii) operating and capital overhead recoveries directly attributable to the Acquired Assets. The TSA was terminated by Longview and Advantage in February, 2014. See "*General Development of the Business – Recent Developments*".

Registration Rights Agreement

Longview entered into the Registration Rights Agreement with Advantage on April 14, 2011. The Registration Rights Agreement provided that for a period commencing 12 months after the date a receipt has been issued for the final prospectus under applicable securities legislation in Canada for the Offering (April 6, 2011) and expiring on the earlier of: (i) a date that is seven years from the date of the Registration Rights Agreement; or (ii) the date that is three months after the date that Advantage ceases to be the beneficial holder of more than 10% of the outstanding common shares of Longview, Advantage may require Longview to prepare, file and obtain a receipt for a final prospectus under applicable securities legislation in Canada qualifying the distribution of some or all of the common shares or other securities of Longview held by Advantage. In addition, during the aforementioned period, Advantage had the right to receive prompt notice should Longview propose to file a prospectus in Canada pursuant to an offering of Longview's securities and Advantage could include some or all of the common shares or other securities of Longview held by Advantage for distribution pursuant to the said offering. Such rights were subject to certain restrictions. As a result of the 2014 Secondary Offering, the Registration Rights Agreement was terminated, as Advantage ceased to be the beneficial owner of any common shares of Longview.

INTEREST 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 National Instrument 51-102 *Continuous Disclosure Obligations* by us during, or related to, our most recently completed financial year other than Sproule Associates Limited, our independent engineering evaluator and PricewaterhouseCoopers LLP, our current auditors. As at the date hereof, none of the principals of Sproule Associates Limited had any registered or beneficial interests, direct or indirect, in any securities or other property of AOG or of our associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. PricewaterhouseCoopers LLP have confirmed that they are independent in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta and the rules of the SEC and the relevant legislation and requirements of the Public Company Accounting Oversight Board (PCAOB).

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of AOG or of any associate or affiliate of AOG.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are PricewaterhouseCoopers LLP, Chartered Accountants, Calgary, Alberta.

Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario acts as the transfer agent and registrar for the Common Shares and the 5.00% Debentures.

AUDIT COMMITTEE INFORMATION

Composition of the Audit Committee

The audit committee (the "**Audit Committee**") is comprised of Messrs. Paul Haggis, Stephen Balog and Ronald McIntosh. The following chart sets out the assessment of each Audit Committee member's independence, financial literacy and relevant educational background and experience supporting such financial literacy.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Ronald A. McIntosh Alberta, Canada	Yes	Yes	Chairman of North American Energy Partners Inc., a publicly traded corporation and a director of Fortaleza Energy Inc., previously known as Alvopetro Inc., and formerly named Fortress Energy Inc. Mr. McIntosh has extensive experience in the energy business. His previous roles included President and Chief Executive Officer of Navigo Energy, Chief Operating Officer of Gulf Canada, Vice President Exploration and International of PetroCanada and Chief Operating Officer of Amerada Hess Canada.

Name, Province and Country of Residence	Independent	Financially Literate	Relevant Education and Experience
Paul Haggis Alberta, Canada	Yes	Yes	Mr. Haggis' was President and Chief Executive Officer of Ontario Municipal Employees Retirement System (OMERS) from September 2003 to March 2007, Interim Chief Executive Officer of the Public Sector Pension Investment Board (PSPIB) during 2003 and Executive Vice-President, Development and Chief Credit Officer of Manulife Financial in 2002. Mr. Haggis has extensive financial markets and public board experience having served on the Board of Directors of Canadian Tire Bank until March 30, 2012. He was a director and Chair of the Investment Committee of the Insurance Corporation of British Columbia and currently serves as an advisor to the committee. He was also Chair of the Audit Committee of C.A. Bancorp and Prime Restaurants Royalty Income Fund, a member of the Board of UBC Investment Management Inc. and a Chairman of Alberta Enterprise Corp., and Chairman of Canadian Pacific Railway. Mr. Haggis holds a Bachelor of Arts degree from the University of Western Ontario and is certified as a Chartered Director through the Directors College at McMaster University.
Stephen Balog Alberta, Canada	Yes	Yes	Principal of Alconsult International Ltd. and President, West Butte Management Inc., private consulting companies that provide technical and business advisory services to oil and gas operators, and director of Questfire Energy Corp. Prior thereto, President and Chief Operating Officer and a Director of Tasman Exploration Ltd. from 2001 to June 2007. Mr. Balog has extensive oil and gas industry experience and was a key contributor to the development and use of the Canadian Oil & Gas Evaluation Handbook as an industry standard for reserves evaluation. He served on the Petroleum Advisory Committee, Alberta Securities Commission from 2009-2011 and has a Bachelor of Science, Chemical Engineering.

Pre-Approval of Policies and Procedures

We have adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by PricewaterhouseCoopers LLP as set forth in item 22 of the Audit Committee charter, which is reproduced below under the heading "*Audit Committee Charter*". The Audit Committee has approved the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, reoccurring or otherwise likely to be provided by PricewaterhouseCoopers LLP during the current fiscal year. The list of services is sufficiently detailed as to the particular services to be provided to ensure that the audit committee knows precisely what services it is being asked to pre-approve and it is not necessary for any member of management to make a judgment as to whether a proposed service fits within pre-approved services.

AUDIT COMMITTEE CHARTER

The following is a summary of our Audit Committee Charter which was originally approved by the AOG Board of Directors on April 30, 2002 and amended in April 2003, April 2004, June 2005, August 2005, October, 2005 and September, 2009:

Purpose

The primary function of the Audit Committee is to assist the Board of Directors of AOG in fulfilling its responsibilities by reviewing: the financial reports and other financial information provided by AOG to any governmental body or the public; AOG's systems of internal controls regarding finance, accounting, legal compliance and ethics that management and the Board have established; and AOG's auditing, accounting and financial reporting processes generally. Consistent with this function, the Audit Committee should endeavour to encourage continuous improvement of, and should endeavour to foster adherence to, AOG's policies, procedures and practices at all levels. In performing its duties, the external auditor is to report directly to the Audit Committee.

The Audit Committee's primary objectives are:

1. To assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of AOG and related matters;

2. To provide better communication between directors and external auditors;

3. To assist the Board's oversight of the auditor's qualifications and independence;

4. To assist the Board's oversight of the credibility, integrity and objectivity of financial reports;

5. To strengthen the role of the outside directors by facilitating discussions between directors on the Audit Committee, management and external auditors;

6. To assist the Board's oversight of the performance of the Corporation's internal audit function and independent auditors; and

7. To assist the Board's oversight of the Corporation's compliance with legal and regulatory requirements.

Composition

The Audit Committee shall be comprised of three or more directors as determined by the Board of Directors, none of whom are members of management of AOG and all of whom are "independent" (as such term is defined in: (a) National Instrument 52-110 — *Audit Committees* ("**NI 52-110**"); and (b) Section 303A.02 of the Corporate Governance Rules of the New York Stock Exchange). All of the members of the Audit Committee shall be "financially literate". The Board of Directors has adopted the definition for "financial literacy" used in NI 52-110. Audit Committee members may enhance their familiarity with finance and accounting by participating in educational programs conducted by AOG or an outside consultant. In addition, at least one member of the Audit Committee must have accounting or related financial management expertise, as the Corporation's Board of Directors interprets such qualification in its business judgment.

The members of the Audit Committee shall be elected by the Board of Directors and remain as members of the Audit Committee until their successors shall be duly elected and qualified. Unless a Chair is elected by the full Board of Directors, the members of the Audit Committee may designate a Chair by majority vote of the full Audit Committee membership.

In connection with its annual review procedures, the Board will determine whether any member or proposed nominee for the Audit Committee serves on the Audit Committees of more than three public companies. To the extent that any member or proposed nominee of AOG serves on the Audit Committees of more than three public companies, the Board will make a determination as to whether such simultaneous services would impair the ability of such member to effectively serve on AOG's Audit Committee and will disclose such determination in AOG's annual information circular and annual report on Form 40-F filed with the Securities and Exchange Commission.

Meetings

The Audit Committee shall meet at least four times annually, or more frequently as circumstances dictate. As part of its job to foster open communication, the Audit Committee should meet at least annually with management, internal auditors and the independent auditors in separate executive sessions to discuss any matters that the Audit Committee or each of these groups believe should be discussed privately. In addition, the Audit Committee or at least its Chair should meet with the independent auditors and management quarterly to review AOG's financials consistent with Section IV.4 below. The Audit Committee should also meet with management and independent auditors on an annual basis to review and discuss annual financial statements and the management's discussion and analysis of financial conditions and results of operations.

A quorum for meetings of the Audit Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Audit Committee shall be the same as those governing the Board.

Responsibilities and Duties

To fulfill its responsibilities and duties, the Audit Committee shall endeavour to:

Documents/Reports Review

1. Review and update this Charter periodically, at least annually, as conditions dictate.

2. Review the organization's annual and interim financial statements, MD&A, earnings press releases and any reports or other financial information submitted to any governmental body or the public, including any certification, report, opinion or review rendered by the independent auditors.

3. Review the reports to management prepared by the independent auditors and management's responses.

4. Review with financial management and the independent auditors the quarterly financial statements prior to their filing or prior to the release of earnings. The Chair of the Audit Committee may represent the entire Audit Committee for purposes of this review.

5. Review significant findings during the year, including the status of previous significant audit recommendations.

6. Periodically assess the adequacy of procedures for the review of corporate disclosure that is derived or extracted from the financial statements.

7. Periodically discuss guidelines and policies to govern the processes by which the Chief Executive Officer and senior management assess and manage the Corporation's exposure to risk.

8. Report regularly to the Board any issues that arise with respect to the quality or integrity of the Corporation's financial statements, compliance with legal or regulatory requirements, performance and independence of the Corporation's auditors, or performance of the internal audit function.

9. To prepare, if required, an Audit Committee report to be included in AOG's annual information circular and proxy statement.

10. Preparing an annual performance evaluation of the Audit Committee.

11. At least annually, obtaining and reviewing the report by the independent auditors describing AOG's internal quality control procedures, any material issues raised by the most recent interim quality-control review, or peer review, of AOG or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by the firm, and any steps to deal with any such issues.

Independent Auditors

12. Recommend to the Board the external auditors to be nominated for appointment by the Shareholders.

13. Approve the compensation of the external auditors.

14. On an annual basis, the Audit Committee should review and discuss with the auditors all significant relationships the auditors have with AOG to determine the auditors' independence. In addition, the Audit Committee will ensure the rotation of the lead audit partner every five years and, in order to ensure continuing auditor independence, consider the rotation of the audit firm itself.

15. Review and, as appropriate, resolve any material disagreements between management and the independent auditors and review, consider and make a recommendation to the Board regarding any proposed discharge of the auditors when circumstances warrant.

16. 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.

17. Periodically consult with the independent auditors, without the presence of management, about internal controls and the fullness and accuracy of the organization's financial statements.

18. Oversee the establishment of an internal audit function.

19. Periodically assess the Corporation's internal audit function, including the Corporation's risk management processes and system of internal controls.

20. Review the audit scope and plan of the independent auditor.

21. Oversee the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for AOG.

22. Pre-approve the completion of any non-audit services by the external auditors and determine which non-audit services the external auditor is prohibited from providing. The Audit Committee may delegate to one or more members of the Audit Committee authority to pre-approve non-audit services in satisfaction of this requirement and if such delegation occurs, the pre-approval of non-audit services by the Audit Committee member to whom authority has been delegated must be presented to the Audit Committee at its first scheduled meeting following such pre-approval. The Audit Committee shall be entitled to adopt specific policies and procedures for the engagement of non-audit services if:

(a) the pre-approval policies and procedures are detailed as to the particular service;

(b) the Audit Committee is informed of each non-audit service; and

(c) the procedures do not include delegation of the Audit Committee's responsibilities to management.

The Audit Committee will satisfy the pre-approval requirement set forth in this paragraph 22 if:

(d) the aggregate amount of all non-audit services that were not pre-approved is reasonably expected to constitute no more than 5% of the total amount of fees paid by AOG and its subsidiary entities to the auditors during the fiscal year in which the services are provided;

(e) AOG or the subsidiary entity, as the case may be, did not recognize the services as non-audit services at the time of the engagement;

(f) the services are promptly brought to the attention of the Audit Committee and approved, prior to completion of the audit, by the Audit Committee or by one or more of its members to whom authority to grant such approvals has been delegated by the Audit Committee; and

23. Review, set and approve hiring policies relating to staff of current and former auditors.

Financial Reporting Processes

24. In consultation with the independent auditors, annually review the integrity of the organization's financial reporting processes, both internal and external.

25. In consultation with the independent auditors, consider annually the quality and appropriateness of the Corporation's accounting principles as applied in its financial reporting.

26. Consider and approve, if appropriate, major changes to AOG's auditing and accounting principles and practices as suggested by the independent auditors or management.

27. Review risk management policies and procedures of AOG (i.e., litigation and insurance).

Process Improvement

28. Request reporting to the Audit Committee by each of management and the independent auditors of any significant judgments made in the management's preparation of the financial statements and the view of each group as to appropriateness of such judgments.

29. Following completion of the annual audit, review separately with each of management and the independent auditors any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information.

30. Review any significant disagreements among management and the independent auditors in connection with the preparation of the financial statements.

31. Review with the independent auditors and management the extent to which changes or improvements in financial or accounting practices, as approved by the Audit Committee, have been implemented. (This review should be conducted at an appropriate time subsequent to implementation of changes or improvements, as decided by the Audit Committee.)

32. Conduct and authorize investigations into any matters brought to the Audit Committee's attention and within the Audit Committee's scope of responsibilities. The Audit Committee shall be empowered to retain and to approve compensation for any independent counsel and other professionals to assist in the conduct of any investigation.

33. Review the systems that identify and manage principal business risks.

34. Establish a procedure for:

(a) the receipt, retention and treatment of complaints received by AOG regarding accounting, internal accounting controls or auditing matters; and

(b) the confidential, anonymous submission by employees of AOG of concerns regarding questionable accounting or auditing matters;

which procedure shall be set forth in a "whistle blower program" to be adopted by the Audit Committee in connection with such matters.

Ethical and Legal Compliance

35. Establish, review and update periodically a Code of Ethical Conduct and ensure that management has established a system to enforce this code.

36. Review management's monitoring of AOG's compliance with the organization's Ethical Code.

37. In consultation with the auditors, consider the review system established by management regarding the Corporation's financial statements, reports and other financial information disseminated to governmental organizations and the public in the context of the applicable legal requirements.

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

39. Review with the organization's counsel legal compliance matters including the trading policies of securities.

Other

40. Perform any other activities consistent with this Charter, AOG's by-laws and governing law, as the Audit Committee or the Board of Directors deems necessary or appropriate.

41. In connection with the performance of its responsibilities as set forth above, the Audit Committee shall have the authority to engage outside advisors and to pay outside auditors and advisors.

AUDIT SERVICE FEES

Auditor Services Fees

The following table discloses fees billed to us by our auditors, PricewaterhouseCoopers LLP.

Type of Service Provided	**2013**	**2012**
Audit Fees(1)	$382,000	$510,000
Audit-Related Fees(2)	66,000	66,000
Tax Fees(3)	40,600	-
Other Fees(4)	-	36,000
Total	488,600	612,000

Notes:

(1) "Audit Fees" include fees necessary to perform the annual audit of the Corporation's consolidated financial statements. Audit Fees also include audit or other services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.

(2) "Audit-Related Fees" include services that are traditionally performed by the auditor. These audit-related services include quarterly reviews of the Corporation's consolidated financial statements.

(3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and general tax advice, including the preparation and filing of Scientific Research & Experimental Development Tax Credits.

(4) "All Other Fees" include all other non-audit products and services.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada

.

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. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, 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. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* which received Royal Assent on June 29, 2012 (the "**Prosperity Act**"). In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings**.** NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010. 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. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%

Oil sands projects are also subject to Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. In addition, concurrent with the implementation of The New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the new royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

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

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

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

Saskatchewan

In Saskatchewan, the amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil being "fourth tier oil", "third tier oil", "new oil" and "old oil" depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for "old oil", "new oil" and "third tier oil", and 250 m^3 per month for "fourth tier oil". Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government, the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, 2012 which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas. The current regulatory scheme provides for certain differences with respect to the administration of "fourth tier gas" which is associated gas.

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on EOR projects pre-payout and 20% of EOR operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR projects; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

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

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. 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. Private ownership of oil and natural gas also exists in such provinces 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 Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, 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 sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. 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 and the imposition of material fines and penalties.

Federal

Pursuant to the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the AER is expected to assume the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

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 seven 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.

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

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82% of the province's oilsands resources and much of the Cold Lake oilsands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oilsands companies' tenure has been (or will be) cancelled in conservation areas and no new oilsands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

The next regional plan to take effect is the South Saskatchewan Regional Plan ("**SSRP**") which covers approximately 83,764 square kilometres and includes 45 % of the provincial population. The SSRP was released in draft form in 2013 and is expected to come into force on April 1, 2014.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

Saskatchewan

In May 2011, Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("**SKOGCA**"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* ("**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* ("**Registry Regulations**"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licences and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Effective May 1, 2013, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);
- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);
- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and
- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

The changes will be implemented over a three-year period. The first phase was implemented in May of 2013, the second phase will be implemented in May of 2014, and the final phase will be implemented in May of 2015. The changes to the LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

Climate Change Regulation

Federal

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

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, for application to regulated sectors on a facility-specific, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated

Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. 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. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing GHG emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended 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 and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes 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 by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 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 SGER. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year and 10% of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also 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.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It 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.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. The MRGGA establishes a framework for achieving the provincial target of a 20% reduction in GHG emissions from 2006 levels by 2020. The MRGGA and related regulations have yet to be proclaimed in force.

RISK FACTORS

The following is a summary of certain risk factors relating to the business of AOG. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this annual information form.

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to, affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. The Corporation'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 or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, Organization of the Petroleum Exporting Countries ("**OPEC**") actions, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural 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 project.

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

Exploration, Development and Production Risks

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 Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and 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, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively 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, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation 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 Corporation.

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 Corporation's business, financial condition, results of operations and prospects.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event the Corporation could incur significant costs.

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 in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves 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 natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

The estimation 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. Such variations could be material.

In accordance with applicable securities laws, the Corporation'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 Corporation's oil and natural 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 Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and 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, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

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 Corporation and may delay exploration and development activities.

Project Risks

The Corporation 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 Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;

- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- 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;
- regulatory changes;
- 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 Corporation could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that it produces effectively.

Seasonality

The level of activity in the Canadian oil and natural 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. In addition, certain oil and natural 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 decreases in the demand for the goods and services of the Corporation.

Gathering and Processing Facilities, Pipeline Systems and Rail

The Corporation delivers its products through gathering and processing facilities and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically and it is projected to continue in this upward trend. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a materially adverse effect on the Corporation's ability to process its production and deliver the same for sale.

Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. The Corporation'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, methods, and reliability of delivery and storage.

Credit Facility Arrangements

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility which may, in certain cases, include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation’s control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in the default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under credit facilities, the lenders under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's credit facility may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Corporation’s lenders use the Corporation’s reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation’s borrowing base. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility which could result in the requirement to repay a portion, or all, of the Corporation's bank indebtedness.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created 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. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by the OPEC and the ongoing global credit and liquidity concerns. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Hedging

From time to time, the Corporation 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, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation 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 Corporation will not benefit from the fluctuating exchange rate.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect the Corporation's production revenues. Accordingly, Canadian/United States exchange rates could affect the future value of the Corporation's reserves as determined by independent evaluators.

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

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the Common Shares.

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 the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation 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, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation 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 Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Third Party Credit Risk

The Corporation 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 Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Liability Management

Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation' deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. See "*Industry Conditions*".

Tax Horizon

It is expected, based upon current legislation, the projections contained in the Sproule Report and various other assumptions that no cash income taxes are to be paid by the Corporation prior to 2018. A lower level of capital expenditures than those contained in the Sproule Report or should the assumptions used by the Corporation prove to be inaccurate, the Corporation may be required to pay cash income taxes sooner than anticipated, which will reduce cash flow available to the Corporation.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, 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.

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. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation 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 Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources diverting 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 may be periodically disposed of so the Corporation 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 Corporation, if disposed of, may realize less than their carrying value on the financial statements of the Corporation.

In addition, acquisitions of oil and gas properties or companies are based in large part on engineering, environmental and economic assessments made by the acquiror, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil and gas, future operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated. Although select title and environmental reviews are conducted prior to any purchase of resource assets, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat the Corporation's title to certain assets or that environmental defects, liabilities or deficiencies do not exist or are greater than anticipated. Such deficiencies or defects could adversely affect the value of the assets acquired and the Corporation's securities.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with greenhouse gas ("**GHG**") emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition.

Geo-Political Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of western Canada. The Corporation 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 Corporation's business, financial condition, results of operations and prospects

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. 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 Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Corporation's access to additional financing may be affected.

Because of global economic volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation'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 affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Issuance of Debt

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

Management of Growth

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation 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 Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Reliance on Key Personnel

The Corporation'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 Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation 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 Corporation.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. The price at which the Common Shares will trade cannot be accurately predicted.

Dilution

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

Conflicts of Interest

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "*Directors and Officers – Conflicts of Interest*".

Dividends

The Corporation has not paid any dividends on its outstanding shares. The amount of future cash dividends paid by the Corporation, if any, will be subject to the discretion of the board of directors of the Corporation and will depend on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by applicable corporate law for the declaration and payment of dividends. See "*Dividend Policy*".

Internal Controls

Effective internal controls are necessary for the Corporation to provide reliable financial reports and to help prevent fraud. Although the Corporation will undertake a number of procedures in order to help ensure the reliability of its financial reports, including those imposed on it under Canadian securities laws, the Corporation cannot be certain that such measures will ensure that the Corporation will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Corporation's results of operations or cause it to fail to meet its reporting obligations. If the Corporation or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Corporation's financial statements and harm the trading price of the Common Shares.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be affected adversely and materially. If the Corporation is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and other liquid hydrocarbons. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. See "*Industry Conditions – Royalties and Incentives*".

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. Additional information on the risks, assumption and uncertainties are found under "*Forward-Looking Statements*".

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a foreign private issuer listed on the NYSE, AOG is not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic Canadian requirements. AOG is, however, required to comply with the following NYSE Rules: (i) AOG must have an audit committee that satisfies the requirements of Rule 10A-3 under the United States Securities Exchange Act of 1934, as amended; (ii) the Chief Executive Officer must promptly notify the NYSE in writing after an executive officer becomes aware of any non-compliance with the applicable NYSE Rules; (iii) submit an executed Section 303A annual written affirmation to the NYSE, as well as a Section 303A interim affirmation each time certain changes occurs to the audit committee; and (iv) provide a brief description of any significant differences between its corporate governance practices and those followed by U.S. domestic issuers under NYSE listing standards. AOG has reviewed the NYSE listing standards followed by U.S. domestic issuers listed under the NYSE and confirms that its corporate governance practices do not differ significantly from such standards.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com and the Corporation’s website at www.advantageog.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, will be contained in the Corporation's Information Circular for the most recent annual meeting of shareholders that involved the election of directors of AOG. Additional financial information is provided for in the Corporation's Consolidated financial statements and management's discussion and analysis for the year ended December 31, 2013.

SCHEDULE "A"

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE (FORM 51-101F3)

Management of Advantage Oil & Gas Ltd. ("**AOG**") is responsible for the preparation and disclosure of information with respect to AOG'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, 2013, estimated using forecast prices and costs.

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

The independent reserves evaluation committee of the board of directors of AOG has:

(a) reviewed AOG'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 independent reserves evaluation committee of the board of directors of AOG has reviewed AOG'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 independent reserves evaluation committee, approved:

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

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

(c) the content and filing of this report.

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

(signed) *"Andy Mah"*
Andy Mah
President and Chief Executive Officer

(signed) *"Craig Blackwood"*
Craig Blackwood
Vice President, Finance and Chief Financial Officer

(signed) *"Ronald A. McIntosh"*
Ronald A. McIntosh
Director

(signed) *"Stephen Balog"*
Stephen Balog
Director

March 27, 2014

SCHEDULE "B"

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

To the Board of Directors of Advantage Oil & Gas Ltd. (the "**Company**"):

1. We have evaluated the Company's Reserves Data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2013, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (County)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule Associates Limited	Evaluation of the P&NG Reserves of Advantage Oil & Gas Ltd.	Canada				
	As of December 31, 2013, prepared December 2013 to March 2014		Nil	2,118,740	Nil	2,118,740
Total			Nil	2,118,740	Nil	2,118,740

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented 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 the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
March 7, 2014

Original Signed by Attila A. Szabo, P. Eng.
Attila A. Szabo, P. Eng.
Manager, Engineering and Director

Original Signed by Nora T. Stewart, P. Eng.
Nora T. Stewart, P. Eng.
Vice-President, Canada and Partner

Original Signed by Brent A. Hawkwood, C.E.T..
Brent A. Hawkwood, C.E.T.
Senior Petroleum Technologist and Partner

Original Signed by Victor Verkhogliad, P.Geol.
Victor Verkhogliad, P.Geol.Senior Petroleum Geologist and Associate

SCHEDULE "B"

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

To the Board of Directors of Longview Oil Corp. (the "**Company**"):

1. We have evaluated the Longview Reserves Data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

2. The Reserves Data are the responsibility of Longview's management. Our responsibility is to express an opinion on the Reserves Data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**"), prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2013, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Advantage Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (County)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule Associates Limited	Evaluation of the P&NG Reserves of Longview Oil Corp.	Canada				
	As of December 31, 2013, prepared December 2013 to March 2014		Nil	613,983	Nil	613,983
Total			Nil	613,983	Nil	613,983

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented 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 the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
March 12, 2014

Original Signed by Attila A. Szabo, P. Eng.
Attila A. Szabo, P. Eng.
Manager, Engineering and Director

Original Signed by Brent A. Hawkwood, C.E.T..
Brent A. Hawkwood, C.E.T.
Senior Petroleum Technologist and Partner

Original Signed by Matthew J. Tymchuk, P. Eng.
Matthew J. Tymchuk, P. Eng.
Petroleum Engineer and Partner

Original Signed by Brian G. Trieber, P.L. (Geol.)
Brian G. Trieber, P.L. (Geol.)
Senior Geological Technologist and Partner

Original Signed by George Strother-Stewart,P.Geol.
George Strother-Stewart, P.Geol.
Senior Petroleum Geologist and Partner

Original Signed by Alec Kovaltchouk, P.Geo.
Alec Kovaltchouk, P. Geo.
Manager, Geoscience and Partner

Original Signed by Nora T.Stewart,P.Eng.
Nora T.Stewart, P.Eng.
Vice-President, Canada and Partner