



Annual Information Form
Fiscal Year Ended December 31, 2010

Dated April 6, 2011

TABLE OF CONTENTS

CONVENTIONS	1
ABBREVIATIONS.....	1
CONVERSION	2
DEFINITIONS	2
SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS.....	4
THE CORPORATION.....	5
GENERAL DEVELOPMENT OF THE BUSINESS	5
History.....	5
NARRATIVE DESCRIPTION OF THE BUSINESS	7
General.....	7
Industry Conditions.....	9
Social or Environmental Policies	16
Risk Factors.....	17
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION	23
DIVIDEND POLICY	36
DESCRIPTION OF SHARE CAPITAL.....	36
MARKET FOR SECURITIES.....	37
Trading Price and Volume	37
DIRECTORS AND OFFICERS	37
Penalties or Sanctions	40
Personal Bankruptcies.....	40
Conflicts of Interest.....	40
PROMOTERS	40
LEGAL PROCEEDINGS AND REGULATORY ACTIONS	40
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS.....	41
TRANSFER AGENT AND REGISTRAR	41
MATERIAL CONTRACTS	41
INTERESTS OF EXPERTS	41
AUDIT COMMITTEE.....	41
Composition of the Audit Committee	41
Relevant Education and Experience.....	42
Audit Committee Oversight	42
Reliance on Certain Exemptions	43
Pre-Approval Policies and Procedures.....	43
External Auditor Service Fees	43
ADDITIONAL INFORMATION	43
APPENDIX A	1
APPENDIX B	1
APPENDIX C	1

CONVENTIONS

Unless otherwise indicated, references herein to “\$” or “dollars” are to Canadian dollars. All financial information with respect to the Corporation has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada. The information in this annual information form (“**Annual Information Form**”) is stated as at December 31, 2010, unless otherwise indicated. For an explanation of the capitalized terms and expressions and certain defined terms, please refer to the section of this Annual Information Form titled “*Definitions*”.

ABBREVIATIONS

	Oil and Natural Gas Liquids		Natural Gas
Bbl	Barrel	Mcf	thousand cubic feet
Bbls	Barrels	Mmcf	million cubic feet
BOPD	Barrel of oil per day	Mcf/d	thousand cubic feet per day
Mbbls	thousand barrels	Mmcf/d	million cubic feet per day
Mmbbls	million barrels	MMBTU	million British Thermal Units
Mstb	1,000 stock tank barrels	Bcf	billion cubic feet
Bbls/d	barrels per day	GJ	Gigajoule
NGLs	natural gas liquids		
STB	Standard tank barrels		
 Other			
AECO	Alberta Energy Company’s natural gas storage facility located at Suffield, Alberta.		
API	American Petroleum Institute		
API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.		
ARTC	Alberta Royalty Tax Credit		
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)		
BOE/D	barrel of oil equivalent per day		
m3	cubic metres		
EPEA	<i>Environmental Protection and Enhancement Act</i> (Alberta)		
MBOE	1,000 barrels of oil equivalent		
OOIP	original oil in place		
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade		
\$000s	thousands of dollars		

CONVERSION

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

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

DEFINITIONS

Wherever used in this Annual Information Form, unless the context otherwise requires, the following words and phrases shall have the meanings set forth below:

“**1276921**” means 1276921 Alberta Ltd., a corporation incorporated under the laws of the Province of Alberta;

“**1332726**” means 1332726 Alberta Ltd., a corporation incorporated under the laws of the Province of Alberta;

“**1332915**” means 1332915 Alberta Ltd., a corporation incorporated under the laws of the Province of Alberta;

“**1332915 Acquisition**” means the acquisition of 1332915 by the Corporation pursuant to the 1332915 Pre-Acquisition Agreement;

“**1332915 Pre-Acquisition Agreement**” means the pre-acquisition agreement dated March 17, 2008 between Seaview and 1332915;

“**1332915 Share**” means a common share in the capital stock of 1332915;

“**2D**” means two dimensional;

“**3D**” means three dimensional;

“**ABCA**” means the *Business Corporations Act* (Alberta);

“**Amalgamation**” means the amalgamation of Seaview Exploration and 1276921 pursuant to the 1276921 Amalgamation Agreement;

“**Board**” or “**Board of Directors**” means the board of directors of Seaview;

“**C3**” means C3 Resources Ltd., a corporation incorporated under the laws of the Province of Alberta;

“**C3 Acquisition**” means the acquisition of C3 by the Corporation pursuant to the C3 Pre-Acquisition Agreement;

“**C3 Pre-Acquisition Agreement**” means the agreement dated July 3, 2008 between the Corporation and C3;

“**Canoil**” means Canoil Inc., a corporation incorporated under the laws of the Province of Alberta;

“**Canoil Agreements**” means, collectively, the Canoil Boundary Lake Agreement and the Canoil Mulligan Agreement;

“**Class A Share**” or “**Class A Shares**” means, respectively, one or more Class A Shares in the capital of Seaview;

“**Class B Share**” or “**Class B Shares**” means, respectively, one or more Class B Shares in the capital of Seaview;

“**Corporation**” or “**Seaview**” means Seaview Energy Inc., a corporation incorporated under the laws of the Province of Alberta;

“**Current Market Price**” at any date shall mean the weighted average trading price per share for Class A Shares for any 30 consecutive trading days selected by Seaview and commencing not more than 45 days before such date on the TSX Venture Exchange, or, if the Class A Shares are not listed thereon, on such stock exchange on which the Class A Shares are listed as may be selected for such purpose by the directors of Seaview, or if the Class A Shares are not listed on any stock exchange, then on the over-the-counter market. The weighted average price shall be determined by dividing the aggregate sale price of all Class A Shares sold on the said exchange or market, as the case may be, during the said 30 consecutive trading days by the total number of such Class A Shares so sold. In the event the foregoing cannot be determined, the Current Market Price shall be established by a qualified independent valuator approved by the board of directors;

“**Fairborne**” means Fairborne Energy Ltd., a corporation incorporated under the laws of the Province of Alberta;

“**NEB**” means the National Energy Board;

“**Peace River Arch Asset Acquisition**” means the acquisition by Seaview of certain assets located in the Peace River Arch area of Alberta pursuant to the Peace River Arch Asset Acquisition Agreement;

“**Peace River Arch Purchase and Sale Agreement**” means the agreement dated effective April 1, 2009 between Seaview and a senior public oil and gas company;

“**Progress**” means Progress Energy Ltd., a corporation incorporated under the laws of the Province of Alberta and a wholly-owned subsidiary of Progress Energy Trust;

“**Progress Acquisition**” means the acquisition by the Corporation of certain light oil assets located in Southeast Saskatchewan from Progress pursuant to the Progress Acquisition Agreement;

“**Progress Acquisition Agreement**” means the agreement dated May 23, 2008 between Progress and Seaview;

“**Seaview Exploration**” means Seaview Exploration Ltd., a corporation incorporated under the laws of the Province of Alberta;

“**Shares**” means the Class A Shares and Class B Shares in the capital of Seaview;

“**Tax Act**” means the *Income Tax Act* (Canada), R.S.C. 1985, c.1 (5th Supp.), as amended;

“**TSXV**” means the TSX Venture Exchange;

“**Units**” means the units comprising the Offering, each of which consists of 400 “flow-through” Class A Shares and 90 “flow-through” Class B Shares; and

“**U.S.**”, “**US**” or “**United States**” means the United States of America.

SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS

All forward-looking statements in this Annual Information Form and in certain documents incorporated by reference herein, are based on assumptions and the Corporation's view of future events which reflect information available at the time the assumption was made. Certain statements contained in this Annual Information Form constitute forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions are intended to identify forward-looking statements. 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. Management of the Corporation believes 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 herein should not be unduly relied upon. These statements speak only as of the date hereof or at the date specified in the documents incorporated by reference into this Annual Information Form.

In particular, this Annual Information Form contains forward-looking statements pertaining to the following:

- oil and natural gas production levels;
- capital expenditure programs;
- the quantity of the oil and natural gas reserves;
- projections of commodity 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 exploration, development and acquisitions; and
- treatment under governmental regulatory regimes including taxation.

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, inter alia, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange or interest rates and stock market volatility;
- failure to realize the anticipated benefits of acquisitions; and
- the other factors discussed under "*Risk Factors*" herein.

Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this Annual Information Form or otherwise, and while the Corporation may choose to do so, it accepts no obligation to update publicly or revise any forward-looking information, whether as a result of new information, future events or otherwise, except as required by securities law.

THE CORPORATION

Seaview Energy Inc. was incorporated under the ABCA on December 13, 2006. The registered office of Seaview is located at 3300, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9 and its head office is located at 1500, 444 – 5th Avenue S.W., Calgary, Alberta, T2P 2T8. Seaview’s articles were amended on August 31, 2007 to remove its private company restrictions.

INTERCORPORATE RELATIONSHIPS

Seaview has the following wholly-owned subsidiary:

Name	Percentage of Voting Securities (Directly or Indirectly)	Jurisdiction of Incorporation
1288916 Alberta Ltd.	100%	Alberta

In addition, Seaview holds a partnership interest in Seaview Energy Partnership (the “**Partnership**”), a partnership formed pursuant to the *Partnership Act* (Alberta). The partners of the Partnership are Seaview and 1288916 Alberta Ltd.

GENERAL DEVELOPMENT OF THE BUSINESS

History

The Corporation was formed in 2006 to operate in Canada as an oil and gas exploration, development and production company. On October 23, 2007, the Class A Shares and Class B Shares commenced trading on the TSXV.

On April 1, 2008, the Corporation completed the 1332915 Acquisition pursuant to the 1332915 Pre-Acquisition Agreement whereby the Corporation acquired all of the outstanding securities of 1332915 for total consideration of approximately \$27.5 million, comprised of the assumption of 1332915’s net debt of approximately \$17.6 million and the issuance of 8,049,250 Class A Shares to the securityholders of 1332915, valued at \$1.00 per Class A Share. Contemporaneous with the completion of the 1332915 Acquisition, Seaview, 1332915 and 1332726, a wholly owned subsidiary of 1332915, were amalgamated and continue to carry on business under the name “Seaview Energy Inc.”. The assets of 1332915 are strategically focused within Seaview’s Peace River Arch core area of northwest Alberta with production as at April 1, 2008 estimated at more than 550 BOE/D (92% natural gas weighted). The 1332915 Acquisition significantly expanded Seaview’s production, reserves, land and drilling inventory, and establishes Seaview as a high growth oil and gas exploration and production company.

On May 2, 2008, Seaview announced the appointment of Mr. Robert G. Peters to the Board of Directors of Seaview.

On May 29, 2008, Seaview completed a bought deal financing of a total of 2,792,000 Class A Shares, including the over-allotment option, issued on a “flow-through” basis at a price of \$2.15 per share for aggregate gross proceeds of \$6,002,800. Gross proceeds from the sale of the “flow-through” shares were used to fund ongoing exploration activities that qualify as Canadian exploration expense as defined in the *Income Tax Act* (Canada), which were renounced to the subscribers for the 2008 taxation year.

On July 10, 2008, Seaview completed a bought deal financing of a total of 2,899,000 Class A Shares, including the over-allotment option, at a price of \$3.45 per Class A Share for aggregate gross proceeds of \$10,001,550. Gross proceeds from the sale of the Class A Shares were used to fund capital expenditures and for general corporate purposes.

On June 26, 2008, Seaview completed the acquisition of certain high quality, long life, operated light oil assets located in Southeast Saskatchewan from Progress pursuant to the Progress Acquisition Agreement for total consideration of \$22.5 million, comprised of the issuance of 8,300,000 Class A Shares and cash consideration of approximately \$5.0 million. In

connection with the Progress Acquisition, Mr. Michael Culbert, President and Chief Executive Officer of Progress Energy Trust, joined the Board of Directors of Seaview.

On July 24, 2008, Seaview completed the C3 Acquisition pursuant to the C3 Pre-Acquisition Agreement. Pursuant to the terms of the C3 Pre-Acquisition Agreement, Seaview acquired all of the issued and outstanding securities of C3 on the basis of an aggregate of 5,891,925 Class A Shares and \$6.3 million cash being issued to the shareholders of C3 and the assumption of C3's net debt of approximately \$12.0 million. Pursuant to the closing of the C3 Acquisition, Mr. Bruce Francis, President and Chief Executive Officer of C3, joined Seaview's Board of Directors. In connection with the C3 Acquisition, Seaview, C3 and C3 Resources Corp. were amalgamated and continue to carry on business under the name "Seaview Energy Inc."

On December 18, 2008, Seaview completed a bought deal financing of a total of 3,000,000 Class A Shares issued on a "flow-through" basis at a price of \$1.60 per share for aggregate gross proceeds of \$4,800,000. Gross proceeds from the sale of the "flow-through" shares were used to fund ongoing exploration activities that qualify as Canadian exploration expense as defined in the *Income Tax Act* (Canada), which were renounced to the subscribers for the 2008 taxation year.

On January 1, 2009, Seaview Exploration and Seaview were amalgamated and continue to carry on business under the name "Seaview Energy Inc."

On June 9, 2009, Seaview entered into the Peace River Arch Asset Acquisition Agreement with a senior public oil and gas company pursuant to which Seaview acquired certain high quality, long life assets (the "**Peace River Arch Assets**") for a purchase price of \$26,500,000. The Peace River Arch Asset Acquisition was completed on June 30, 2009. See "*General Corporate Development of the Business – Significant Acquisition*" below for further details.

On June 16, 2009, Seaview completed a bought deal financing of a total of 11,246,500 subscription receipts (the "**Subscription Receipts**"), including the over-allotment option, at a price of \$0.95 per Subscription Receipt (the "**Subscription Receipt Offering**") and 4,167,000 Class A Shares issued on a "flow-through" basis at a price of \$1.20 per share (the "**Flow-Through Offering**") for aggregate gross proceeds of \$15,700,000. Proceeds from the Subscription Receipt Offering were used to partially finance the Peace River Arch Asset Acquisition. The proceeds from the Subscription Receipt Offering were deposited in escrow and were released upon the completion of the Peace River Asset Acquisition. Each Subscription Receipt entitled the holder thereof to receive one Class A Share upon the earlier of (i) the issuance of a final receipt on behalf of each of the securities regulatory authorities in each jurisdiction in which the Subscription Receipts were offered, in connection with the filing of a short form prospectus qualifying the distribution of the Class A Shares underlying the Subscription Receipts; and (ii) four months and a day following the closing of the Subscription Receipt Offering. On July 10, 2009, Seaview obtained a final receipt in connection with the filing of a short form prospectus in each jurisdiction in which the Subscription Receipts were offered and each Subscription Receipt was deemed to be exercised for one Class A Share.

On April 12, 2010, Seaview entered into an agreement (the "**Sale Agreement**") to dispose of all of the Corporation's oil and gas assets located in southeast Saskatchewan including the Alameda, Rocanville, Steelman and Wapella properties for a total consideration of \$33,000,000. The transactions contemplated by the Sale Agreement were completed on April 29, 2010.

From December 17, 2009 to October 18, 2010, Seaview entered into various farmin and participation agreements relating to the earning of interests in the Wapiti area of Alberta. Pursuant to such agreements, to-date Seaview has participated in the drilling, casing and completion of 10 horizontal wells (5.6 net) to earn an interest in 26.25 sections of land in the Wapiti area at an average working interest of 52%. In addition, Seaview has acquired an aggregate of 8.5 sections of land from four separate arm's length oil and gas companies for aggregate consideration of \$1.4 million. See "*Statement of Reserves Data and Other Oil and Gas Information – Oil and Gas Properties*".

On April 6, 2010, Seaview announced the appointment of Mr. Daryl H. Gilbert as Chairman of the Board of Directors of Seaview.

NARRATIVE DESCRIPTION OF THE BUSINESS

General

The business plan of the Corporation is to focus its exploration efforts in two to three core areas in Alberta in order to develop an asset portfolio offering both geologic and geographic diversity to manage overall investment risk. The Corporation's primary area of operation is the Peace River Arch area of northwest Alberta and the Wapiti area of Alberta. Business development is focused on regions where management has previous experience. Seaview's goal is to create sustainable and profitable growth in production and cash flow. To accomplish this, Seaview has, and will continue to pursue, aggressive, yet focused, acquisition, exploration, exploitation and development opportunities.

Seaview plans to acquire interests in oil and gas exploration and development prospects primarily through internal generation and through farm ins and participation with other industry partners. Emphasis will be placed on exploration targets near established infrastructure that have the potential to be placed on production soon after drilling success. Seaview's focus areas will characteristically have moderate drilling and operating costs and offer access to processing and transportation systems. Typical drilling depths between 500 and 2,300 metres will allow Seaview to explore for oil and gas in the Cretaceous, Triassic and Mississippian formations with drilling and completion costs in the \$250,000 to \$3,500,000 range, including horizontal completion and fracturing.

Seaview has initially been focusing exploration efforts in the Peace River Arch area, northwest of Grande Prairie, Alberta, to develop the Corporation's first core area. To date, Seaview has been active in securing oil and gas interests in this area through the acquisition of 1276921, 1332915, C3 Energy Inc. and the Peace River Arch Asset Acquisition and a strategic farm-in agreement within the Wapiti area targeting a cardium light oil resource play. In addition, Seaview has been and will continue to pursue additional interests within its focus areas through acquisitions, farm in agreements and other industry participation agreements. Management of Seaview has extensive experience in oil and gas exploration and development in Seaview's areas of focus. The Corporation's investment decisions will largely be opportunity driven.

Seaview plans to acquire, exploit and explore for oil and gas prospects. Seaview will focus on acquisitions of oil and gas properties where management believes further exploration, exploitation and development opportunities exist. While largely opportunity driven, Seaview plans to pursue a balanced portfolio of crude oil and natural gas prospects. In selecting exploration, exploitation and development prospects, management will choose those that offer an appropriate combination of risk and economic reward, recognizing that all drilling involves substantial risk and that a high degree of competition exists for prospects. To achieve sustainable and profitable growth, Seaview believes in controlling the timing and costs of its projects whenever possible. Accordingly, Seaview will seek to become the operator of its properties to the greatest extent possible.

In order to focus its exploration and development drilling programs, Seaview will consider some or all of the following criteria prior to allocating capital to new projects:

- required capital and degree of risk relative to expected production rate and potential reserves volumes;
- quality of the anticipated production and reserves. Seaview's exploration efforts will be focused towards long-life, low-decline reserves with reserves life indices greater than five years;
- favourable payout and return on investment. Seaview will strive to identify projects which have the ability to achieve payout in less than three years and have the ability to generate a return on investment of at least 15% per annum;
- availability and application of seismic to reduce risk. Seaview will attempt to minimize risk by pursuing plays that are supported by seismic. Furthermore, Seaview intends to maintain capital efficiency by shooting or acquiring seismic data prior to land acquisition;
- availability of operatorship;
- adjacent land opportunities;

- potential for additional reservoir development and repeatability of the play type; and
- target areas where infrastructure is available and accessible and the ability to expand the infrastructure is also significant. All new wells drilled (exploration or development) should have the reasonable expectation of being placed on production within six months from the date of completion.

It is important to recognize that exploration drilling involves substantial risk and no assurance can be given that drilling will prove successful in establishing commercially recoverable reserves. While Seaview believes that it has the skills and resources necessary to achieve its objectives, participation in the exploration for and development of oil and natural gas has a number of inherent risks. See “*Risk Factors*”.

Strategic acquisitions of oil and gas properties which are synergistic to Seaview’s exploration focus will be a key component of Seaview’s future growth plan. Management has industry experience in a wide range of producing areas of Western Canada, in addition to its initial focus areas. Management believes this diverse experience provides the capability to expand the scope of Seaview’s activities and opportunities through selective asset and corporate acquisitions. Seaview intends to finance acquisitions through a combination of debt and equity. When reviewing potential participations or acquisitions, Seaview will consider some or all of the following criteria:

- the opportunity must present identifiable and measurable upside, either through drilling, completions, reservoir management or production/facility optimization;
- producing properties should exhibit low decline and long reserves life, typically greater than seven years;
- operatorship or the possibility of becoming operator;
- ensuring facilities and infrastructure provide near-term market access, with capability of expansion to accommodate increased activity;
- additional facility opportunities, particularly if there is a consistent stream of third party processing income that could be increased through additional tie-ins, whereby facilities associated with the acquisition of producing properties may represent up to 30% of total asset value;
- required return on investment from acquired producing properties should be at least 15% per annum, with a recycle ratio greater than two. The recycle ratio is a measure for evaluating the effectiveness of a company’s reinvestment program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the operating netback per barrel of oil equivalent to that year’s reserve finding and development costs;
- all acquisitions, when fully exploited, should enhance the net asset value per share of Seaview; and
- utilizing commodity price and exchange rate assumptions from projections by major independent petroleum engineering firms and future contract pricing.

In addition to the above criteria, in circumstances where Seaview seeks to acquire assets of a material nature with proven reserves, prior to the investment decision being finalized, Seaview intends to obtain an independent engineering report (whether from the vendor of such assets or otherwise) relating to such proven reserves.

The Board may, in its discretion, approve asset or corporate acquisitions or investments that do not conform to these guidelines based upon the Board’s consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserves life and asset quality.

Personnel

As of December 31, 2010, the Corporation had 12 full-time employees and 5 consultants

Industry Conditions

The oil and gas industry is subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing 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.

Canadian Government Regulation

The oil and gas industry is subject to extensive controls and regulations imposed by various levels of government. It is not expected that any of these controls or regulations will affect the operations of the Corporation in a manner materially different than they would affect other oil and gas companies of similar size. 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 more significant aspects of the legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing - Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. The price depends in part on oil type and quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the NEB. Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

Pricing and Marketing - Natural Gas

In Canada, the price of natural gas sold in interprovincial and international trade is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of 2 to 20 years (in quantities of not more than 30,000 m³/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council.

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

Pipeline Capacity

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

The North American Free Trade Agreement ("NAFTA")

On January 1, 1994, NAFTA became effective among the governments of Canada, the United States of America and Mexico. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the United States of America or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period),

(ii) impose an export price higher than the domestic price, and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations, which govern land tenure, royalties, production rates, environmental protection and other matters. In all Canadian jurisdictions where we operate, producers of oil and natural gas are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and natural gas produced from Crown and freehold lands, respectively. The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

Alberta

In terms of oil or natural gas production from Crown lands, royalties are payable to the Province of Alberta. On February 16, 2007, the Government of Alberta announced a review of the province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil, natural gas and oil sands to be conducted by a panel of experts, with the assistance of individual Albertans and key stakeholders. The purpose of this process was to ensure that Albertans are receiving a fair share from energy development through royalties, taxes and fees.

On October 25, 2007, the Government of Alberta unveiled a new royalty regime for determining Crown royalty rates in Alberta (the "**Royalty Framework**"), effective January 1, 2009. The new Royalty Framework introduced new royalties applicable to all conventional oil and natural gas wells and bitumen production, with the exception of those subject to the transitional royalty rate discussed below.

The new Royalty Framework eliminated the previous tier system for conventional oil, which was based on the vintage or discovery date of the oil, and implemented a sliding rate formula based on both the commodity price of oil and well production. Subject to certain available incentives, effective from the January 2011 production month royalty rates for conventional oil production under the Royalty Framework range from a base rate of 0% to a cap of 40%. This represents an increase from the previous rate cap of 35% under the tier system, but a decrease from the rate cap of 50% under the Royalty Framework prior to January 2011. New royalty rates will be determined on a monthly basis.

The new Royalty Framework also eliminated the previous tier system for natural gas, which was also based on the vintage or discovery date of the gas, and implemented a sliding rate formula based on both the commodity price of the gas and well production. This eliminated the option to use a corporate average reference price. The natural gas royalty formula also provides for a reduction based on the measured depth of the well below 2,000 metres (the "**Depth Factor Adjustment**"), as well as the acid gas content of the produced gas (the "**Acid Gas Adjustment**"). Subject to certain available incentives, effective from the January 2011 production month royalty rates for natural gas production under the Royalty Framework range from a base rate of 5% to a cap of 36%. This represents an increase from the previous rate cap of 35% under the tier system, but a decrease from the rate cap of 50% under the Royalty Framework prior to January 2011.

Under the new Royalty Framework, the royalty rate applicable to natural gas liquids is a flat rate of 40% for pentanes and 30% for butanes and propane.

In terms of oil and natural gas production obtained from lands other than Crown lands, taxes are payable to the Province of Alberta. Approximately 19% of the mineral rights in the Province of Alberta are freehold mineral rights not owned by the

Crown. The tax levied in respect of freehold oil and gas production in the Province of Alberta is calculated annually based on a rate dependent on the prescribed tax rate, the quantity of produced oil or gas, and the unit value of the produced oil or gas.

Transitional Incentive

In late November 2008, the Alberta government announced details of an optional five-year transitional royalty program (the “**Transitional Program**”) applicable to conventional oil and natural gas wells drilled to measured depths from 1,000 to 3,500 metres, with a spud date on or after November 19, 2008. For each eligible well, the producer can make a one-time election to produce the well under the Transitional Program royalty rates or the new Royalty Framework rates. The Transitional Program royalty rates would only apply to production from January 1, 2009 until December 31, 2013. As of January 1, 2014, all production subject to the Transitional Program will revert to the new Royalty Framework regime. Operators electing the Transitional Program rates are not eligible for the Depth Factor Adjustment or the Acid Gas Adjustment, which are specific to the Royalty Framework, but are otherwise not excluded from available incentive programs, subject to eligibility as discussed below. On March 11, 2010, the Government of Alberta announced that the Transitional Program would continue until its originally announced expiration, however, effective January 1, 2011, no new wells would be eligible for the selection of the Transitional Program royalty rates. Wells which have already opted for the Transitional Program royalty rates prior to January 1, 2011 have the option to continue under the Transitional Program royalty rates until the expiry of the Transitional Program, or to opt out of the Transitional Program by February 15, 2011 in favour of the new Royalty Framework rates.

Incentive Programs

From time to time the governments of Canada, Alberta, British Columbia and Saskatchewan have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced planning projects. Such programs are generally introduced when commodity prices are low, and are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. These programs reduce the amount of Crown royalties otherwise payable.

Oil and natural gas royalty holidays and reductions for specific wells reduce the amount of Crown royalties paid to the provincial governments. Prior to 2007, the Alberta Royalty Tax Credit (“**ARTC**”) program provided a rebate on Alberta Crown royalties paid in respect of eligible producing properties, having the effect of increasing net income. Under the ARTC, a producer of oil or natural gas was entitled to a tax credit against the royalties payable to the Crown, however this program was phased out on December 31, 2006.

The Royalty Framework also eliminated some previously available incentives, and introduced certain revised or updated incentive programs.

With respect to conventional oil, the Royalty Framework eliminated the Third Tier Exploratory Well Royalty Exemption, the Re-activated Well Royalty Reduction, the Low Productivity Well Royalty Reduction, the Horizontal Re-entry Well Royalty Program, and the Experimental Project Petroleum Royalty.

With respect to natural gas, the Royalty Framework eliminated the Deep Gas Royalty Holiday and the Royalty Adjustment Program for Deep Marginal Gas Wells.

Pursuant to the new Royalty Framework, the Deep Oil Exploratory Well Program, the Enhanced Recovery of Oil Royalty Reduction Program (“**EOR Program**”), the Natural Gas Deep Drilling Program, and the Innovative Energy Technologies Program (the “**IETP**”) were either created or retained.

The *Deep Oil Exploratory Well Regulation* provides a limited royalty exemption for qualifying exploratory oil wells spudded or deepened between January 1, 2009 and December 31, 2013 that are deeper than 2,000 metres and have a producing interval below 2,000 metres. Existing oil wells approved under the discontinued Third Tier Exploratory Well Royalty Exemption and qualifying for the Deep Oil Exploratory Well Program were transitioned into the new program on January 1, 2009.

With respect to the EOR Program, the *Enhanced Recovery of Oil Royalty Reduction Regulation* provides that Alberta Energy may approve royalty reductions for qualifying enhanced oil recovery projects.

The *Natural Gas Deep Drilling Regulation* provides a limited royalty reduction for qualifying exploratory and development natural gas wells spudded or deepened on or after May 1, 2010, with producing intervals that are deeper than 2,000 metres.

The IETP was originally intended to promote producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. This program has been retained under the new Royalty Framework. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy determines which projects qualify for the IETP, as well as the level of support that will be provided. The deadline for the IETP's fifth round of applications was November 15, 2009.

On March 3, 2009, the Government of Alberta announced an additional incentive program, the Drilling Royalty Credit (the "**DRC**"), in respect of conventional oil and gas wells drilled on Alberta Crown lands. On June 25, 2009, the Government of Alberta announced the extension of the DRC for one additional year, expiring on April 1, 2011. The *Drilling Royalty Credit Regulation* provides that for qualifying wells drilled for the purpose of extracting conventional oil or natural gas and with a spud date and finish drill date between April 1, 2009 and April 1, 2011, the operator will receive a royalty credit of \$200 per metre drilled, up to a prescribed maximum percentage of the operator's royalties. The maximum percentage will be determined on a sliding scale ranging from 10% to 50%, based on the operator's production, with a higher maximum percentage available to lower producing operators. The DRC is only available to companies that are or will be recognized as having royalty payment obligations pursuant to applicable regulation. Any DRC royalty credits not used prior to March 31, 2011 will be forfeited.

On March 3, 2009, the Government of Alberta also announced the New Well Royalty Reduction (the "**NWRR**") incentive program. The *New Well Royalty Reduction Regulation* provides that the NWRR will be available to qualifying wells that commence or recommence producing conventional oil or natural gas between April 1, 2009 and March 31, 2011. Pursuant to the *New Well Royalty Reduction Regulation*, the NWRR reduces royalties on production from qualifying wells to a maximum royalty rate of 5% until the earlier of either 12 production months from the date of first production, the date that the first 7949 cubic metres of eligible oil or oil equivalent is produced, the date the well becomes part of a Project under the *Oil Sands Royalty Regulation, 2009*, or March 31, 2012, whichever occurs first. On March 11, 2010, as part of a larger modification of royalty rates under the Royalty Framework, the Government of Alberta announced that the NWRR will become a permanent feature of Alberta's royalty regime. The NWRR is now referred to as the New Well Royalty Rate as it provides for a 5% royalty from the outset, as opposed to reducing an existing royalty to 5%.

In addition, on May 27, 2010 the Government of Alberta announced further initiatives to stimulate investment in emerging resources and technologies. The Shale Gas New Well Royalty Rate ("**SGNWRR**") will reduce royalties on production from qualifying wells to a maximum royalty rate of 5% for 36 production months, with no limitation on volume. The Coalbed Methane New Well Royalty Rate ("**CMNWRR**") will reduce royalties on production from qualifying wells to a maximum royalty rate of 5% until the earlier of either 36 production months from date of first production or the date that the first 11,924 cubic metres of oil equivalent is produced. The Horizontal Gas New Well Royalty Rate ("**HGNWRR**") will reduce royalties on production from qualifying wells to a maximum royalty rate of 5% until the earlier of either 18 production months from date of first production or the date that the first 7949 cubic metres of oil equivalent is produced. Finally, the Horizontal Oil New Well Royalty Rate ("**HONWRR**") will reduce royalties on production from qualifying wells to a maximum royalty rate of 5% until the prescribed time or volume limit is met. The time and volume limits increase with the depth of metres drilled, from a minimum of 7949 cubic metres of oil equivalent and 18 months for wells drilled to measured depths from 0 to 2,499 metres, to a maximum of 15,899 cubic metres of oil equivalent and 48 months for wells drilled to measured depths in excess of 4,500 metres. Final implementation of the foregoing initiatives is expected in June 2011. The NWRR, SGNWRR, and CMNWRR will apply retroactively to production produced on or after May 1, 2010. The HGNWRR and HONWRR will be apply retroactively to spud dates on or after May 1, 2010.

Both the DRC and NWRR apply to wells under the Royalty Framework as well as those wells electing the Transitional Program rates. In relation to conventional oil wells eligible for both the NWRR and the Deep Oil Exploratory Well Program, the date constraints and volume limits under each program will run concurrently. In relation to natural gas wells

eligible for both the NWRR and the NGDDP and any of the 5% royalty rates, including the New Well Royalty Rate (NWRR), the Horizontal Gas NWRR, the Coal Bed Methane NWRR or the Shale Gas NWRR, the 5% royalty rate will be applied first, with the NGDDP benefits applied after the expiration of the 5% rate. However, the 60 calendar month benefit under the NGDDP begins on the well's finished drilling date, not with the expiry of the 5% royalty rate. In addition, the NWRR will reduce the royalty reduction that is available for wells under the EOR Program and the IETP.

The implementation of the changes to the royalty regime in Alberta is subject to certain risks and uncertainties. The significant changes to the royalty regime require new and amended legislation, and development of proprietary software to support the calculation and collection of royalties. Additionally, certain proposed changes contemplate further public and/or industry consultation. There may be modifications introduced to the proposed royalty structure.

The new royalty regime could increase the Corporation's average royalty rate. The changes to royalties could also have a negative impact on net earnings, funds from operations, cash flow from operating activities, operating netbacks, and reserve values, which could create uncertainty as to the recoverability of the carrying value of the Corporation's petroleum and natural gas assets. Nonetheless, the Corporation expects the economics of production from its properties will be acceptable under the new royalties.

Saskatchewan

With respect to production obtained from Crown lands in the Province of Saskatchewan, the amount payable as a royalty in respect of crude oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the price of the oil. For both Crown royalty and freehold production tax purposes, crude oil is categorized by oil type as either "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". Additionally, the oil in each category is subdivided according to the conventional royalty and production tax classifications as either "fourth tier oil" (introduced October 1, 2002), "third tier oil", "new oil", or "old oil". Depending on the categorization and classification of the oil, monthly production, and a prescribed reference price determined monthly by the Saskatchewan Ministry of Energy and Resources ("**SER**"), the royalty reserved to the Crown ranges from 0% to 45%.

Similarly, the amount payable as a royalty in respect of natural gas in the Province of Saskatchewan depends on the vintage of the gas, the type of gas production, the quantity of gas produced in a month, and the price of the gas. For both Crown royalty and freehold production tax purposes, natural gas is categorized as either non-associated gas or associated gas, the former being produced from gas wells and the latter being produced from oil wells. Additionally, the gas is divided according to the royalty and production tax classifications as either "fourth tier gas" (introduced October 1, 2002), "third tier gas", "new gas", or "old gas". Depending on the categorization and classification of the natural gas, monthly production, and a reference price, the royalty reserved to the Crown ranges from 0% to 45%. Subject to certain restrictions, the operator may elect to use either a prescribed reference price determined monthly by SER, or a reference price based on the operator's average gas price in a month. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on associated gas is less than on non-associated natural gas.

Approximately one-fifth of the mineral rights in the Province of Saskatchewan are freehold mineral rights not owned by the Crown. With respect to production from lands other than Crown lands, the tax levied in respect of freehold oil and gas production in the Province of Saskatchewan is determined by reducing the Crown royalty rate that would otherwise be payable if the lands were Crown lands by a fixed amount. Currently, this reduction ranges from 6.9% to 12.5% depending on the classification of the oil or gas.

On June 14, 2010 the SER released a letter outlining significant changes to the current administrative provisions related to natural gas valuation under the government's Process Renewal and Infrastructure Management Enhancements ("**PRIME**") initiative. Among other changes, PRIME will introduce a new index based pricing for natural gas and will eliminate operators' option to elect between the monthly reference price prescribed by the SER and the operator's average monthly gas price for royalty/tax purposes. All natural gas, other than natural gas produced from oil wells and sold to a gas plant at or upstream of the plant inlet, will be valued based on the SER prescribed price for royalty/tax purposes. Furthermore, natural gas is generally bought and sold on an energy basis. To eliminate existing equity issues related to the current volumetric based royalty/tax calculation, the SER will be converting to an energy based calculation. Consequently, the

price used to value natural gas production for royalty/tax purposes will be expressed in dollars per gigajoule. While an exact implementation date for PRIME has not been set, the SER anticipates that it will be implemented in late 2011.

Incentives

On October 1, 2002, a modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from qualifying oil wells and gas wells in the Province of Saskatchewan with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of 0%. Horizontal gas wells drilled between June 1, 2010 and March 31, 2013 inclusive are also classified as qualifying exploratory gas wells for royalty/tax purposes and subject to a maximum royalty rate of 2.5% and a freehold production tax rate of 0%. In addition, oil produced from Enhanced Oil Recovery (“**EOR**”) projects that commenced operation prior to April 1, 2005 are subject to a cost sensitive royalty regime determined by prescribed formulas which include a number of variables and which differentiate between pre and post project payout. EOR projects that commenced operation on or after April 1, 2005 are also subject to a cost sensitive royalty regime that provides a royalty of 1% of gross EOR revenue prior to project payout and 20% of EOR operating income after project payout and a freehold production tax rate of 0% prior to payout and 8% of EOR operating income after payout.

In 1975 the Government of Saskatchewan introduced a Royalty Tax Rebate (“**RTR**”) as a response to the federal government disallowing the deduction of crown royalties and similar taxes as a business expense for income tax purposes. As of January 1, 2007, the RTR was allowed to wind down as a result of the federal government’s initiative to reintroduce the full deduction of crown royalties in computing income for federal and provincial income tax purposes in respect of taxation years commencing after 2006. Commencing January 1, 2007, the carry forward period for any outstanding RTR balance was limited to 7 years.

British Columbia

Producers of oil and natural gas in the province of British Columbia are also required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. The amount payable as a royalty in respect of oil depends on the vintage of the oil or the type of oil, the quantity of oil produced in a month and the value of the oil. The royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and a prescribed minimum price.

The royalties payable on oil and natural gas may also be reduced pursuant to various incentive programs made available, including royalty credits for deep gas exploration, summer drilling, and infrastructure development, special royalty rates for marginal and ultra-marginal gas, and a recent stimulus package aimed at increasing exploration and production in the British Columbia oil and gas industry introduced on August 6, 2009. Eligibility for such incentive programs is subject to the satisfaction of specified criteria and conditions provided in legislation, regulation and guidelines.

Land Tenure

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

Environmental Protection Requirements

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 international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, or emissions of

various substances produced in association with oil and natural gas operations, requirements with respect to oilfield waste handling and storage, habitat protection, and minimum setbacks of oil and gas activities from fresh water bodies. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Environmental laws may impose remediation obligations and costs on “persons responsible” with respect to contaminated property, including persons responsible for the substance causing the contamination, persons responsible for the release, past and present owners of the property, and occupiers of the property. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material, and in the suspension or revocation of necessary licences and approvals, as well as civil liability for damage caused by pollution. Certain environmental protection legislation may subject the Corporation to statutory strict liability in the event of an accidental spill or discharge from a licensed facility, meaning that fault need not be established by claimants affected by such a spill or discharge.

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* (the “*EPEA*”) and the *Oil and Gas Conservation Act* (“*Alberta OGCA*”). The *EPEA* and the *Alberta OGCA* impose strict environmental standards with respect to releases of effluents and emissions, include reporting and monitoring obligations, and impose significant penalties for non-compliance. For example, regulations enacted under the *EPEA* target sulphur oxide and nitrous oxide emissions from oil and gas operations

In 2008 the Corporation commenced operations in Saskatchewan as well as Alberta, and as such is also subject to the Saskatchewan *Environmental Management and Protection Act, 2002* (the “*EMPA*”) and *Oil and Gas Conservation Act* (the “*Saskatchewan OGCA*”). The *EMPA* and the *Saskatchewan OGCA* regulate and control harmful or potentially harmful activities and substances, any release of such substances to the air, water, or land, and remediation obligations in Saskatchewan. Certain development activities in Saskatchewan, depending on the location and potential environmental impact, may require a screening or an environmental impact assessment under the provincial *Environmental Assessment Act*.

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

The Corporation does not currently carry on operations in British Columbia, however in the event that the Corporation elects to operate in British Columbia, the provincial *Environmental Assessment Act* will apply. This legislation rolls the

previous processes for the review of major energy projects into a single environmental assessment process which contemplates public participation in the environmental review prior to project development. British Columbia also announced a new Energy Plan in 2007 which calls for flare reduction, emissions reduction, unconventional development, and increased recovery from existing reserves, among other clean energy and technology incenting policies.

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 third parties and may require Seaview to incur costs to remedy any such discharge not covered by Seaview's insurance. Although Seaview maintains insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit. Further, Seaview expects incremental future compliance costs in light of increasingly more complex environmental protection requirements, some of which may require the installation of emissions monitoring and measuring devices and the verification of emissions data.

The Corporation believes it is in material compliance with environmental legislation at this time. The Corporation is committed to meeting its responsibilities to protect the environment wherever it operates and will take such steps as required to ensure compliance with environmental legislation. No assurance can be given however, 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 adversely affect the Corporation's financial condition, results of operations or prospects.

As at December 31, 2010, Seaview owned approximately 185 wells for which abandonment and reclamation costs are expected to be incurred by Seaview. As disclosed in Seaview's consolidated financial statements for the year ended December 31, 2010, the total amount required to settle the liability associated with its legal asset retirement obligations is estimated to be approximately \$5.5 million. Seaview estimates abandonment and reclamation costs by taking into consideration the costs associated with decommissioning, abandonment, remediation, and reclamation, and also includes the salvage values of any existing equipment which can be reasonably salvaged, all adjusted according to its working interest and discounted in accordance with NI 51-101. The costs and salvage values are individually attributed to assets then aggregated to determine the aggregate liability.

As at December 31, 2010, Seaview has accrued \$2.3 million for the fair value of the asset retirement obligations. The liability will be funded by future cash flow as required. The Corporation did not incur any abandonment expenses in 2010.

Social or Environmental Policies

The health and safety of employees, contractors and the public, as well as the protection of the environment, is of utmost importance to Seaview. To this end the Corporation has instituted a comprehensive environmental policy to which it, as well as its employees and contractors are required to adhere. The Corporation endeavours to conduct its operations in a manner that will minimize both adverse effects and consequences of emergency situations by:

- complying with government regulations and standards, particularly relating to the environment, health and safety;
- operations consistent with industry codes, practises and guidelines;
- ensuring prompt, effective response and repair to emergency situations and environmental incidents;
- providing training to employees and contractors to ensure compliance with corporate safety and environmental rules and procedures; and
- communicating openly with members of the public regarding its activities.

Seaview believes that all employees have a vital role in achieving excellence in environmental, health and safety performance. This is best achieved through careful planning and the support and active participation of everyone involved.

To further ensure that the Corporation achieves excellence in health and safety performance an emergency response plan and a corporate safety policy have been implemented. Furthermore, the Corporation aligns itself with the best industry practices to ensure positive results.

Risk Factors

Exploration, Development and Production Risks

Oil and natural gas exploration involves a high degree of risk and there is no assurance that expenditures made on future exploration by the Corporation will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof.

The Corporation currently has a limited number of specific identified exploration or development prospects. Management will continue to evaluate prospects on an ongoing basis in a manner consistent with industry standards and their past practices. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Corporation will be able to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic.

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

In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires, spills or leaks. These risks could result in personal injury, loss of life, and environmental or property damage. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition.

Limitations of Insurance

The Corporation's involvement in the exploration for and development of oil and gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, property damage, personal injury or other hazards. Although the Corporation has obtained insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be 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 such 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, could have a material adverse effect on the Corporation's financial position, results of operations or prospects.

Prices, Markets and Marketing of Crude Oil and Natural Gas

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond the control of the Corporation. World prices for oil and natural gas have fluctuated widely in recent years. Any material decline in prices could result in a reduction of net production revenue. Certain wells or other projects may become uneconomic as a result of a decline in world oil prices and natural gas prices, leading to a reduction in the volume of the Corporation's oil and gas reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's future net production revenue, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Corporation are in part determined by the borrowing base of the Corporation. A sustained material decline in prices from historical average prices could limit or reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation, and could require that a portion of any existing bank debt of the Corporation be repaid.

In addition to establishing markets for its oil and natural gas, the Corporation must also successfully market its oil and natural gas to prospective buyers. The marketability and price of oil and natural gas which may be acquired or discovered by the Corporation will be affected by numerous factors beyond its control. The Corporation will be affected by the differential between the price paid by refiners for light quality oil and the grades of oil produced by the Corporation. The ability of the Corporation to market its natural gas may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. The Corporation will also likely be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities and related to operational problems with such pipelines and facilities and extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business. The Corporation has limited direct experience in the marketing of oil and natural gas.

Substantial Capital Requirements; Liquidity

The Corporation anticipates that it will make substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, the Corporation may have limited ability to expend 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. Moreover, future activities may require the Corporation to alter its capitalization significantly. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

Recent Distress in Financial Markets

In the future, the Corporation may require financing to grow its business. The recent distress affecting the financial markets and the possibility that financial institutions may consolidate or go bankrupt has reduced levels of activity in the credit markets. This could diminish the amount of financing available to companies. In addition, such turmoil in the financial markets could significantly increase the Corporation's costs associated with borrowing. The Corporation's liquidity and its ability to access the credit or capital markets may also be adversely affected by changes in the financial markets and the global economy. Continuing turmoil in the financial markets could make it more difficult for the Corporation to access capital, sell assets, refinance existing indebtedness, enter into agreements for new indebtedness or obtain funding through the issuance of securities. In addition, there could be a number of follow-on effects from the credit crisis on the Corporation, including insolvency of customers, key suppliers and other counterparties to the Corporation and foreign exchange derivative instruments.

Global Economic Downturn

In the event of a continued general economic downturn or a recession, there can be no assurance that the business, financial condition and results of operations of the Corporation would not be materially adversely affected.

Competitive Conditions

The Corporation actively competes for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than the Corporation. The Corporation's competitors include major integrated oil and natural gas companies and numerous other independent oil and natural gas companies and individual producers and operators.

The oil and gas industry is highly competitive. The Corporation's competitors for the acquisition, exploration, production and development of oil and natural gas properties, and for capital to finance such activities, include companies that have greater financial and personnel resources available to them than the Corporation.

Certain of the Corporation's customers and potential customers are themselves exploring for oil and natural gas, and the results of such exploration efforts could affect the Corporation's ability to sell or supply oil or gas to these customers in the future. The Corporation's ability to successfully bid on and acquire additional property rights, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements with customers will be dependent upon developing and maintaining close working relationships with its future industry partners and joint operators and its ability to select and evaluate suitable properties and to consummate transactions in a highly competitive environment.

Environmental Protection Requirements

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 international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Environmental laws may impose remediation obligations and costs on "persons responsible" with respect to contaminated property, including persons responsible for the substance causing the contamination, persons responsible for the release, past and present owners of the property, and occupiers of the property. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material, and in the suspension or revocation of necessary licences and approvals, as well as civil liability for damage caused by pollution.

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 Corporation estimates the liability associated with its legal asset retirement obligations and provides for this estimate in its financial statements. As at December 31, 2010 the Corporation has accrued \$2,273,110 for the fair value of the asset retirement obligations. The liability will be funded by future cash flow as required. The Corporation did not incur any abandonment expenses in 2010.

The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to foreign governments and third parties and may require the Corporation to incur costs to remedy such discharge. 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 adversely affect the Corporation's financial condition, results of operations or prospects.

Reserve Replacement

The Corporation's future oil and natural gas reserves, production, and cash flows to be derived therefrom are highly dependent on the Corporation successfully acquiring or discovering new reserves. Without the continual addition of new

reserves, any existing reserves the Corporation may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on the Corporation's ability to develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. There can be no assurance that the Corporation's future exploration and development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas.

Reliance on Operators and Key Employees

The Corporation may not be the operator of certain oil and gas properties in which it acquires an interest. To the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of the Corporation will be largely dependent upon the performance of its management and key employees. The Corporation does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on the Corporation.

Corporate Matters

To date, the Corporation has not paid any dividends on its outstanding Class A Shares and does not anticipate the payment of any dividends on its Class A Shares or its Class B Shares for the foreseeable future. Certain of the directors and officers of the Corporation are also directors and officers of other oil and gas companies involved in natural resource exploration and development, and conflicts of interest may arise between their duties as officers and directors of the Corporation and as officers and directors of such other companies. Such conflicts must be disclosed in accordance with, and are subject to such other procedures and remedies as apply under the ABCA.

Permits and Licenses

The operations of the Corporation may require licenses and permits from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development at its projects. In addition, the requirements applicable to sustain existing permits and licenses may change or become more stringent over time and there is no assurance that the Corporation will have the resources or expertise to meet its obligations under such licenses and permits.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the 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. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or available on favourable terms

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Corporation's debt levels above industry standards. 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 in the future on a timely basis to take advantage of business opportunities that may arise.

Availability of Drilling Equipment and Access Restrictions

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment 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.

Geo-Political Risks

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

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the 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 and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the 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, could be expected to realize less than their carrying value on the financial statements of the Corporation.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "*Narrative Description of the Business – Industry Conditions*". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. On October 25, 2007 the Alberta Government unveiled a new royalty and tax regime applicable to oil, gas and oil sands – see "*Narrative Description of the Business – Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's intended business, financial condition and results of operations. In order to conduct oil and natural gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Aboriginal Claims

Aboriginal peoples have claimed title and rights to 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 this could have an adverse effect on the Corporation and its operations.

Business Cycle and 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. Also, 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 declines in the demand for the goods and services of the Corporation. Furthermore, while the Corporation's business is generally not cyclical, its revenue from the sale of natural gas is highly seasonal, with demand for natural gas rising during cold winter months and hot summer months.

Title to Assets

While title reviews will generally be conducted prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which could result in a reduction of the revenue received by the Corporation.

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 operations and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth could have a material adverse impact on its business, operations and prospects.

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, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the 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.

Third Party Credit Risk

The Corporation is or 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 could have a material adverse effect on the Corporation and its cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Alternatives to and Changing Demand for Petroleum Products

Fuel 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 crude oil 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.

Renegotiation or Termination of Contracts

It is not expected that the Corporation's business will be affected in the current financial year by the renegotiation or termination of contracts or sub contracts.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserve Data

In accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities, Sproule Associates Limited (“**Sproule**”) prepared a report (the “**Sproule Report**”) dated February 2, 2011 and effective December 31, 2010. The Sproule Report evaluated, as at December 31, 2010, the Corporation's oil, NGLs and natural gas reserves. The tables below are a summary of the oil, NGLs and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Report based on constant and forecast price and cost assumptions. The tables summarize the data contained in the Sproule Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly. **The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by Sproule. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Corporation's oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.**

The Sproule Report is based on certain factual data supplied by the Corporation and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Corporation's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by the Corporation to Sproule and accepted without any further investigation. Sproule accepted this data as presented and neither title searches nor field inspections were conducted. All statements relating to the activities of the Corporation for the year ended December 31, 2010 include a full year of operating data on the properties of the Corporation.

Summary of Oil and Natural Gas Reserves – Forecast Prices and Costs

	Gross Reserves				Net Reserves			
	Light and Medium Crude Oil	Heavy Crude	Natural Gas Liquids	Natural Gas	Light and Medium Crude Oil	Heavy Crude	Natural Gas Liquids	Natural Gas
	Mbbls	Mbbls	Mbbls	Mmcf	Mbbls	Mbbls	Mbbls	Mmcf
Proved								
Developed Producing	460.9	-	176.0	23,500	394.0	-	114.3	18,953
Developed Non-Producing	94.2	-	32.0	1,650	80.1	-	21.7	1,401
Undeveloped	580.8	-	177.1	5,189	501.0	-	127.2	4,292
Total Proved	1,135.9	-	385.1	30,339	975.1	-	263.2	24,645
Probable	1,187.5	-	410.3	21,887	985.3	-	276.2	17,545
Total Proved plus Probable	2,323.3	-	795.4	52,226	1,960.4	-	539.4	42,191

Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs

	Before Future Income Tax Expenses and Discounted at					Unit Value Before Income Tax Discounted at
	0%	5%	10%	15%	20%	10%/year
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(\$/boe)
Proved						
Developed Producing	106,113	82,299	67,706	57,893	50,850	18.46
Developed Non-Producing	11,234	8,949	7,472	6,453	5,710	22.29
Undeveloped	43,673	23,821	14,074	8,471	4,901	10.48
Total Proved	161,020	115,070	89,253	72,817	61,462	16.70
Probable	162,387	85,460	53,835	37,273	27,213	12.86
Total Proved plus Probable	323,407	200,530	143,088	110,090	88,675	15.01

	After Future Income Tax Expenses and Discounted at				
	0%	5%	10%	15%	20%
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Proved					
Developed Producing	91,387	71,654	59,526	51,336	45,431
Developed Non-Producing	8,383	6,629	5,495	4,713	4,143
Undeveloped	32,840	17,224	9,467	4,968	2,087
Total Proved	132,609	95,508	74,488	61,016	51,661
Probable	121,736	63,356	39,190	26,459	18,697
Total Proved plus Probable	254,345	158,864	113,678	87,476	70,358

Additional Information Concerning Future Net Revenue – Undiscounted

Forecast Prices and Costs

	Revenue	Royalties	Operating	Develop- ment	Abandon- ment Costs	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Income Taxes
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Total Proved Reserves	323,712	53,748	79,567	27,012	2,365	161,020	28,411	132,609
Total Proved plus Probable	641,783	112,702	149,738	52,821	3,114	323,407	69,062	254,345

Future Net Revenue by Production Group – Forecast Prices and Costs

	Future Net Revenue Before Income Taxes and (Discounted at 10%/Year)	Unit Value Before Income Taxes (Discounted at 10%/Year)
	(M\$)	(\$/boe)
Proved		
Light and Medium Crude Oil (including solution gas and associated by-products)	30,924	19.67
Heavy Crude Oil (including solution gas and associated by-products)	-	-
Natural Gas (including associated by-products)	58,329	15.46
Proved plus Probable		
Light and Medium Crude Oil (including solution gas and associated by-products)	55,347	17.34
Heavy Crude Oil (including solution gas and associated by-products)	-	-
Natural Gas (including associated by-products)	87,741	13.84

Notes and Definitions

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

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

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

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

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

“**Undeveloped**” reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (e.g., 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, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator’s assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

“**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 + probable reserves.

The following terms, used in the preparation of the Sproule Report (as defined herein) and this document, have the following meanings:

“**associated gas**” means the gas cap overlying a crude oil accumulation in a reservoir.

“**Corporation**” or “**Seaview**” means Seaview Energy Inc.

“**crude oil**” or “**oil**” means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

“**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 the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (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 the 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.

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

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

- (e) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as “geological and geophysical costs”);
- (f) 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;
- (g) dry hole contributions and bottom hole contributions;
- (h) costs of drilling and equipping exploratory wells; and
- (i) costs of drilling exploratory type stratigraphic test wells.

“exploratory well” means a well that is not a development well, a service well or a stratigraphic test well.

“field” means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms “structural feature” and “stratigraphic condition” are intended to denote localized geological features, in contrast to broader terms such as “basin”, “trend”, “province”, “play” or “area of interest”.

“future prices and costs” means future prices and costs that are:

- (j) generally accepted as being a reasonable outlook of the future;
- (k) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation issuer 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 paragraph (a).

“future income tax expenses” means future income tax expenses estimated (generally, year-by-year):

- (l) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;
- (m) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;
- (n) taking into account estimated tax credits and allowances (for example, royalty tax credits); and
- (o) applying to the future pre-tax net cash flows relating to the reporting issuer’s oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

“future net revenue” means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using or forecast prices and costs.

“gross” means:

- (p) in relation to the Corporation’s interest in production or reserves, its “company gross reserves”, which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;
- (q) in relation to wells, the total number of wells in which the Corporation has an interest; and
- (r) in relation to properties, the total area of properties in which the Corporation has an interest.

“natural gas” means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

“natural gas liquids” means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

“net” means:

- (s) in relation to the Corporation’s interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation’s royalty interests in production or reserves;
- (t) in relation to the Corporation’s interest in wells, the number of wells obtained by aggregating the Corporation’s working interest in each of its gross wells; and
- (u) in relation to the Corporation’s interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

“non-associated gas” means an accumulation of natural gas in a reservoir where there is no crude oil.

“operating costs” or **“production costs”** means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

“production” means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

“property” includes:

- (v) fee ownership or a lease, concession, agreement, permit, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;
- (w) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and
- (x) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as “producer” of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

“property acquisition costs” means costs incurred to acquire a property (directly by purchase or lease, or indirectly by acquiring another corporate entity with an interest in the property), including:

- (y) costs of lease bonuses and options to purchase or lease a property;
- (z) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;
- (aa) brokers’ fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

“proved property” means a property or part of a property to which reserves have been specifically attributed.

“reservoir” means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

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

“solution gas” means natural gas dissolved in crude oil.

“stratigraphic test well” means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) “exploratory type” if not drilled into a proved property; or (b) “development type”, if drilled into a proved property. Development type stratigraphic wells are also referred to as “evaluation wells”.

“support equipment and facilities” means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

“unproved property” means a property or part of a property to which no reserves have been specifically attributed.

“well abandonment costs” means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

Pricing Assumptions - Forecast Prices and Costs

The Sproule Report used the following pricing, exchange rate and inflation rate assumptions as of December 31, 2010 in estimating Seaview’s reserves data using forecast prices and costs.

Year	CRUDE OIL			NATURAL GAS	NATURAL GAS LIQUIDS		Inflation (%)	US/CAN Exchange Rate (\$US/Cdn)
	WTI Crude Oil	Edmonton Par Price	Cromer Medium	Alberta AECO Gas Price	Pentanes Plus FOB Field Gate	Butanes FOB Field Gate		
		40 ⁰ API Crude Oil	29.3 ⁰ API Crude Oil					
	(\$US/Bbl)	(\$Cdn/Bbl)	(\$Cdn/Bbl)	(\$Cdn/mmbtu)	(\$Cdn/Bbl)	(\$Cdn/Bbl)		
(1)	(2)	(3)						
Forecast								
2011	88.40	93.08	85.63	4.04	95.32	62.44	1.5	0.932
2012	89.14	93.85	86.34	4.66	96.11	62.95	1.5	0.932
2013	88.77	93.43	85.02	4.99	95.68	62.67	1.5	0.932
2014	88.88	93.54	84.18	6.58	95.79	62.75	1.5	0.932
2015	90.22	94.95	85.45	6.69	97.24	63.69	1.5	0.932

Thereafter

Rate of 1.5%

Notes:

- (1) West Texas Intermediate at Cushing Oklahoma 40 degrees API, 0.4% sulphur.
- (2) Edmonton Light Sweet 40 degrees API, 0.3% sulphur.
- (3) Comer Medium (29.3° degrees API Heavy stream).

The weighted average realized sales prices before hedging for the period ended December 31, 2010 were \$4.24/Mcf for natural gas and \$76.39/Bbl for crude oil.

Reconciliations of Changes in Reserves and Future Net Revenue

Reserves Reconciliation

The following table sets forth a reconciliation by country of Seaview's gross proved reserves, gross probable reserves and gross proved plus probable reserves at December 31, 2010 against such reserves as at December 31, 2009 based on forecast price and cost assumptions.

Canada

	Light and Medium Oil			Associated and Non-Associated Gas			Natural Gas Liquids		
	Total Proved	Total Probable	Total Plus Probable	Total Proved	Total Probable	Total Plus Probable	Total Proved	Total Probable	Total Plus Probable
	(Mbbbl)	(Mbbbl)	(Mbbbl)	(MMcft)	(MMcft)	(MMcft)	(Mbbbl)	(Mbbbl)	(Mbbbl)
December 31, 2009	1,277.6	519.9	1,797.5	34,257	19,698	53,955	154	123.5	277.5
Extensions	745.8	921.2	1,667.0	2,195	2,754	4,949	214.3	272.7	487.0
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	102.0	22.7	124.6	(1,930)	(1,108)	(3,038)	1.4	(5.0)	(3.6)
Discoveries	-	-	-	1,291	275	1,566	4.9	1.0	5.9
Acquisitions	39.4	20.3	59.7	411	173	584	41.1	17.2	58.3
Dispositions	(940.6)	(303.9)	(1,244.5)	(274)	(174)	(448)	-	-	-
Economic Factors	(1.4)	7.3	5.9	(309)	270	(39)	(0.9)	0.9	-
Production	(86.9)	-	(86.9)	(5,302)	-	(5,302)	(29.7)	-	(29.7)
December 31, 2010	1,135.9	1,187.5	2,323.3	30,339	21,887	52,226	385.1	410.3	795.4

Undeveloped Reserves

The following discussion generally describes the basis on which Seaview attributes Proved and Probable Undeveloped Reserves and its plans for developing those Undeveloped Reserves.

Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied in, wells drilled near the end of the fiscal year or wells further away from Seaview gathering systems. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a two year time frame.

The table set forth below sets forth the proved undeveloped reserves volumes that were first attributed in 2008, 2009 and 2010.

Company Gross Reserves First Attributed By Year				
Product Type	Units	2008	2009	2010
Light & Medium Oil	Mbbl	4.4	3.6	560.4
Heavy Oil	Mbbl	-	-	-
Natural Gas	Mmcf	1,113	405	3,115
Natural Gas Liquids	Mbbl	3.7	6.8	161.7
Total: Oil Equivalent	MBOE	193.6	77.9	1,241.3

Probable Undeveloped

Probable undeveloped reserves are generally those reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be onstream within a two year timeframe.

The table set forth below sets forth the probable undeveloped reserves volumes that were first attributed in 2008, 2009 and 2010.

Company Gross Reserves First Attributed By Year				
Product Type	Units	2008	2009	2010
Light & Medium Oil	Mbbl	94.4	44.7	830.9
Heavy Oil	Mbbl	-	-	-
Natural Gas	Mmcf	5,192	3,276	2,458
Natural Gas Liquids	Mbbl	22.4	28.3	245.8
Total: Oil Equivalent	MBOE	982.1	619.0	1,486.4

Significant Factors or Uncertainties Affecting Reserve Data

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

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, 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 either be positive or negative.

Seaview typically has available three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favourable terms.

Future Development Costs

The table below sets out the development costs by country deducted in the estimation of future net revenue attributable to proved reserves (using forecasted prices and costs only) and proved plus probable reserves (using forecast prices and costs only).

Canada

	Forecast Prices and Costs	
	Proved Reserves	Proved Plus Probable Reserves
	(M\$)	(M\$)
2011	12,585	25,966
2012	14,382	26,809
2013	-	-
2014	-	-
2015	-	-
Remaining Years	46	46
Total Undiscounted	27,012	52,821

Seaview typically has available three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favourable terms.

Oil and Gas Properties

The following is a description of Seaview's principal oil and gas properties as at December 31, 2010. All production volumes in this section represent Seaview's net interest as at December 31, 2010.

The Corporation's principal oil and gas properties are located in the Peace River Arch area, in northwest Alberta. Seaview has established its asset base in the Peace River Arch area through a combination of the corporate acquisitions, property acquisitions and several significant farm-ins. Seaview's primary natural gas properties are located at Balsam and Boundary Lake and the Wapiti property is the Company's primary light oil property.

The Peace River Arch properties were collectively producing approximately 2509 BOE/D at December 31, 2010 comprised of 13.1 Mmcf/d natural gas and 325 Bbls/d oil and natural gas liquids. Seaview's reserve life index (RLI) is 12.9 years based on Proven plus Probable reserves of approximately 11.8 MBOE. Seaview has an average working interest of 50% in approximately 156,070 acres of gross land in this area.

Boundary Lake and Balsam are the most significant properties representing 69% of the corporate production; the properties are producing 1080 and 643 BOE/D respectively. Seaview has working interest of 90% and operates the majority of its production in the Boundary Lake asset. During 2010, Seaview was successful in optimizing production from the Kiskatinaw "U" gas pool through the tie-in of the 02/14-5-86-12W6M gas well in October. Additionally a Triassic gas well at 16-6-86-12W6M was brought on production in December. In Balsam, Seaview's average working interest of production is 70%.

Seaview has established its asset base in the Wapiti Cardium light oil resource play through combination of lands acquisitions and several significant farm-ins. Over the course of 2010, Seaview has accumulated 42.5 sections (22.8 net) of prospective Cardium petroleum and natural gas rights and has successfully drilled 6 Cardium horizontal wells utilizing multi stage fracturing completion techniques. As of December 31, 2010, Seaview was producing approximately 151 BOE/D from 4 (2.2 net) wells. Seaview has an average working interest of 56% in approximately 25,280 acres of gross land in this area.

Seaview's strategy in 2010 focused on accumulating a large, contiguous land position in the Wapiti area and the drilling of exploration wells to assess to the potential of this light oil resource play. As a result of the exploration drilling success in 2010, Seaview's focus during 2011 will be the continued development of this asset. Seaview has experimented with various completion and production technologies in order to optimize production. This asset provides a long term development opportunity for a light oil resource play.

Seaview has production from the following other properties in this area: Gordondale, Doe, Pouce Coupe, Sinclair, Valhalla and Clayhurst. Such properties were producing in aggregate approximately 635 BOE/D as of December 31, 2010.

Drilling Activity and Location of Production and Wells

Oil and Gas Wells

The following table summarizes Seaview's interest as at December 31, 2010 in wells that are producing and non-producing.

	Producing Wells				Non Producing Wells			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Peace River Arch	28	14.4	91	40.4	10	4.3	85	39.0
Total	28	14.4	91	40.4	10	4.3	85	39.0

Notes:

- (1) "Gross" refers to all wells in which Seaview has either a working interest or a royalty interest.
- (2) "Net" refers to the aggregate of the percentage working interests of Seaview in the gross wells before deduction of royalties.
- (3) "Non-producing wells" refers to wells which have encountered and are capable of producing crude oil or natural gas but which are not producing due to lack of available transportation facilities, available markets or other reasons. Non-producing wells in which Seaview has an interest are located no further than 10 kilometres from existing pipelines.

Properties with No Attributed Reserves

The following table summarizes the gross and net acres of unproved properties in which Seaview has an interest and also the number of net acres for which Seaview's rights to explore, develop or exploit will, absent further action, expire within one year of December 31, 2010.

	Gross Undeveloped Acres	Net Undeveloped Acres	Net Acres Expiring Within One Year
Canada	67,165	30,720.6	2,880
Total	67,165	30,720.6	2,880

Notes:

- (1) "Gross Acres" means the total number of acres in which Seaview has an interest.
- (2) "Net Acres" means the aggregate of the percentage working interest of Seaview in the gross acres.

Forward Contracts

The Corporation has entered into the following financial instruments during the financial year ended December 31, 2010.

Product	Contract	Volume	Pricing Point	Price	Cost/Premium	Term
Natural Gas	Put	2,000 GJ/d	AECO Monthly	\$5.80/GJ	\$1.05/GJ	Jan 1/11 – Dec 31/11
Natural Gas	Put	6,140 GJ/d	AECO Monthly	\$4.00/GJ	-	Jan 1/11 – Dec 31/11
Natural Gas	Call	3,000 GJ/d	AECO Monthly	\$7.04/GJ	-	Jan 1/12 – Dec 31/12
Crude Oil	Put	200 bbl/d	WTI ⁽¹⁾	\$86.00/bbl	\$11.00/bbl	Jan 1/11 – Dec 31/11
Crude Oil	Call	100 bb/d	WTI ⁽¹⁾	\$90.00/bbl	-	Jan 1/12 – Dec 31/12
Crude Oil	Call	200 bbl/d	WTI	\$75.00/bbl	-	Jan 1/12 – Dec 31/12

Note:

- ⁽¹⁾ Based on the arithmetic average of the settlement prices for WTI Light Sweet Crude, for each business day, converted to Canadian dollars at the Bank of Canada daily noon rate for each corresponding business day.

Subsequent to year end, the latter two crude oil contracts for 100 bb/d and 200 bbl/d in the above mentioned table were terminated and replaced with the following contracts respectively:

Product	Contract	Volume	Pricing Point	Price	Cost/Premium	Term
Crude Oil	Call	100 bb/d	WTI ⁽¹⁾	\$88.25/bbl	-	Jan 1/13 – Dec 31/13
Crude Oil	Call	200 bbl/d	WTI	\$72.50/bbl	-	Jan 1/13 – Dec 31/13

Additional Information Concerning Abandonment Costs

The Corporation did not incur well abandonment costs in 2010. The Corporation estimates well abandonment costs area by area. Abandonment costs discussed herein include estimated decommissioning and abandonment. Such costs are included in the Sproule Report as deductions in arriving at future net revenue. The expected total abandonment costs included in the Sproule Report (forecast pricing) under the total proved reserves category is \$2.4 million undiscounted (\$0.9 million discounted at 10%), of which a total of 0.1 million, \$0.1 million and \$0.2 million (all undiscounted) is estimated to be incurred in 2011, 2012 and 2013, respectively.

Tax Horizon

The Corporation was not required to pay income taxes during the year ended December 31, 2010. Taxes payable beyond 2010 will become a function of commodity prices, production volumes and capital expenditures. Based on a strategy of re-investing fully all internally generated cash flow in an exploration and development program and based on the commodity prices used in the Sproule Report, the Corporation estimates that it will not be required to pay income taxes until after 2012.

Costs Incurred

The following tables summarize by country Seaview's property acquisition costs, exploration costs and development costs for the year ended December 31, 2010.

Canada

	Property Acquisition Costs		Exploration Costs	Development Costs
	Proved Properties	Unproved Properties		
Total (\$ thousands)	\$2,816	\$576	\$19,102	-

Drilling Activity

The following tables summarize by country the gross and net exploration and development wells in which Seaview participated during the year ended December 31, 2010.

Canada

	Exploratory Wells		Development Wells		
	Gross	Net	Gross	Net	
Oil		7	4.3	-	-
Gas		3	2.3	-	-
Service Wells		-	-	-	-
Dry Wells		1	1.0	-	-
Total		11	7.6	-	-

Notes:

- (1) "Gross" wells means all wells in which Seaview has a working interest.
- (2) "Net" wells refer to the aggregate of the percentage working interests on Seaview in the gross wells before the deduction of royalties.

Production History

The following tables disclose by country, on a quarterly basis for the year ended December 31, 2010, the Corporation's share of average daily production volume, prior to royalties, and the prices received, royalties paid, production costs incurred and netbacks on a per unit of volume basis for each product type.

Canada

Average Daily Production Volume

	Three Months Ended				
	Mar 31, 2010	Jun 30, 2010	Sep 30, 2010	Dec 31, 2010	Total
Natural gas (Mcf/d)	16,544	17,084	13,299	14,016	15,223
Light and Medium Crude Oil (Bbl/d)	400	264	198	211	268
NGL (Bbl/d)	79	110	124	94	102
Total (BOE/D)	3,237	3,221	2,538	2,641	2,907

Prices Received, Royalties Paid, Production Costs and Netback – Light and Medium Crude Oil and NGLs

(\$ per Bbl)	Three Months Ended				
	March 31, 2010	June 30, 2010	Sept. 30, 2010	Dec. 31, 2010	Total
Prices Received	\$75.82	\$73.59	\$67.04	\$72.76	\$72.69
Hedging gain (loss)	(\$2.90)	(\$2.71)	(\$2.58)	(\$6.50)	(\$3.53)
Royalties Paid	(\$13.62)	(\$26.75)	(\$11.35)	(\$17.33)	(\$17.20)
Production Costs	(\$14.65)	(\$7.65)	(\$6.31)	(\$8.49)	(\$10.03)
Transportation Costs	(\$1.96)	(\$2.20)	(\$2.39)	(\$4.15)	(\$2.57)
Netback	\$42.68	\$34.28	\$44.42	\$36.29	\$39.36

Prices Received, Royalties Paid, Production Costs and Netback – Natural Gas

(\$ per Mcf)	Three Months Ended				
	March 31, 2010	June 30, 2010	Sept. 30, 2010	Dec. 31, 2010	Total
Prices Received	\$4.11	\$5.23	\$3.68	\$3.80	\$4.24
Hedging gain (loss)	\$0.48	(\$0.11)	\$0.66	\$0.68	\$0.41
Royalties Paid	(\$0.33)	(\$0.76)	(\$0.13)	(\$0.19)	(\$0.37)
Production Costs	(\$1.35)	(\$1.75)	(\$0.82)	(\$0.84)	(\$1.22)
Transportation Costs	(\$0.21)	(\$0.20)	(\$0.22)	(\$0.22)	(\$0.21)
Netback	(\$2.70)	(\$2.42)	\$3.15	\$3.23	\$2.85

Production Volume by Field

The following table discloses for each important field, and in total, the Corporation's production volumes for the financial year ended December 31, 2010 for each product type.

Field	Light and Medium Crude Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/D)	%
Peace River Arch	201	15,209	102	2,838	98
Southeast Saskatchewan	67	14	-	69	2
Total	268	15,223	102	2,907	100

Production Estimates

The following tables disclose by country for each product type the total volume of production estimated by Sproule for 2011 (forecast pricing) in the estimates of gross proved reserves and gross probable reserves disclosed above under the heading "Oil and Natural Gas Reserves and Net Present Value of Future Net Revenue".

Canada

Field	Light and Medium Crude Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (BOE/D)	%
Peace River Arch	413	14,364	148	2,955	99
Total Proved	413	14,572	156	2,998	100
Peace River Arch	475	17,283	168	3,524	97
Total Probable	475	17,899	189	3,647	100

DIVIDEND POLICY

The Corporation has not declared or paid any dividends since its incorporation. The Corporation does not intend to pay dividends on its Class A Shares or Class B Shares in the foreseeable future. The future payment of dividends will depend on the earnings and financial condition of the Corporation and such other factors as the board of directors of the Corporation consider appropriate.

DESCRIPTION OF SHARE CAPITAL

Class A Shares

Seaview has an unlimited number of Class A Shares authorized. As at the date hereof, there are 65,553,018 fully paid and non-assessable Class A Shares issued and outstanding. The holders of Class A Shares are entitled to dividends if, as and when declared by the board of directors pro-rata with the Class B Shares; to one vote per share at any meeting of the shareholders of Seaview; and upon liquidation to receive, pro-rata with the Class B Shares, all assets of Seaview as are distributable to the holders of shares.

Class B Shares

Seaview also has an unlimited number of Class B Shares authorized. As at the date hereof, there are 1,053,540 fully paid and non-assessable Class B Shares issued and outstanding. The holders of Class B Shares are entitled to one vote per share at any meeting of the shareholders of Seaview. The holders of Class B Shares are entitled to dividends, if, as and when declared by the board of directors, pro-rata with the Class A Shares, and upon liquidation to receive, pro-rata with the Class A Shares, all assets of Seaview as are distributable to the holders of shares.

The Class B Shares will be convertible, at the option of Seaview, at any time after June 1, 2010 and before May 31, 2012 into Class A Shares. The number of Class A Shares obtained upon conversion of each Class B Share will be equal to \$10.00 divided by the greater of \$1.00 and the Current Market Price of the Class A Shares at the effective date of conversion.

If Seaview fails to exercise the option to convert the Class B Shares into Class A Shares by the close of business on May 31, 2012, then the Class B Shares shall be convertible, at the option of the shareholder, at any time after June 1, 2012 and before June 30, 2012 into Class A Shares. The number of Class A Shares obtained upon conversion of each Class B Share will be equal to \$10.00 divided by the greater of \$1.00 and the Current Market Price of the Class A Shares at the effective date of conversion. Any Class B Shares outstanding at the close of business on June 30, 2012 shall be automatically converted into Class A Shares. The number of Class A Shares obtained upon conversion of each Class B Share will be equal to \$10.00 divided by the greater of \$1.00 and the Current Market Price of the Class A Shares at the effective date of conversion.

The conversion option may be exercised by shareholders by notice in writing given to Olympia Trust Company, the transfer agent of Seaview, accompanied by the share certificate or certificates representing the Class B Shares in respect of which the holder desires to exercise such conversion privilege.

MARKET FOR SECURITIES

Trading Price and Volume

The Class A Shares and Class B Shares of the Corporation are listed and posted for trading on the TSXV under the symbols "CVU.A" and "CVU.B", respectively. The following table sets forth the price range and trading volume of these securities as reported by the TSXV for the period January 1, 2010 to December 31, 2010:

Month	Class A Shares			Class B Shares		
	High	Low	Volume	High	Low	Volume
<u>2010</u>						
January	1.29	1.06	3,026,834	6.95	6.25	16,050
February	1.24	1.10	1,407,414	7.59	6.80	18,550
March	1.17	0.82	3,248,310	7.10	6.51	10,350
April	1.21	0.89	11,589,886	7.59	6.02	24,150
May	1.19	0.90	1,292,550	7.30	6.40	52,827
June	1.11	0.90	4,091,806	7.07	6.51	380,780
July	1.14	0.99	1,581,742	7.25	6.65	3,400
August	1.37	1.02	5,660,101	7.49	6.66	47,723
September	1.20	1.11	4,156,646	7.50	7.25	6,800
October	1.17	0.95	7,481,130	7.50	7.27	22,600
November	1.23	1.01	2,948,167	7.35	7.35	18,550
December	1.24	1.16	2,319,689	8.20	7.89	8,000

DIRECTORS AND OFFICERS

The names, municipality of residence and principal occupation during the last five years of each of the directors and senior officers of the Corporation are as follows:

Name and Place of Residence	Principal Occupation During The Last Five Years	Position Held with the Corporation
Michael J.J. Wuetherick Calgary, Alberta Canada	President, Chief Executive Officer and Director of the Corporation Prior thereto, Chief Operating Officer of Signal Energy Inc.	President, Chief Executive Officer and Director

Name and Place of Residence	Principal Occupation During The Last Five Years	Position Held with the Corporation
Stephanie A. Bunch Calgary, Alberta Canada	Vice-President, Finance and Chief Financial Officer of the Corporation Prior thereto, Manager, Investor Relations of Canetic Resources Trust Prior thereto, Manager, Special Projects, Business Development of Acclaim Energy Trust	Vice-President, Finance and Chief Financial Officer
H. Scott Oldale Calgary, Alberta Canada	Vice President, Exploration, Chief Operating Officer and Director of the Corporation Prior thereto, President of Benacadie Energy Ltd. Prior thereto, Vice President, Exploration of Stride Energy	Vice President, Exploration, Chief Operating Officer and Director
Davin Chandler Calgary, Alberta Canada	Vice President, Engineering of the Corporation Prior thereto, President of Stride Energy Ltd.	Vice President, Engineering
Timothy L. Campbell Calgary, Alberta Canada	Vice President, Land of the Corporation Prior thereto, Vice President, Land for Signal Energy Inc. Prior thereto, Vice President, Land & Corporate Development for Hawker Resources Inc.	Vice President, Land
Sanjib Gill Calgary, Alberta Canada	Partner, McCarthy Tétrault LLP Prior thereto, Associate, McCarthy Tétrault LLP	Corporate Secretary
Gregory G. Turnbull, Q.C. (3),(4) Calgary, Alberta Canada	Regional Managing Partner, McCarthy Tétrault LLP	Director
James B. Howe ^{(1),(4)} Calgary, Alberta Canada	President of Bragg Creek Financial Consultants Ltd.	Director
Steven R. VanSickle (1),(2),(3),(5) Calgary, Alberta Canada	President and Chief Executive Officer of Fairborne Energy Ltd.	Director
Daryl Gilbert ^{(2),(5)(6)} Calgary, Alberta Canada	Managing Director of JOG Capital Inc. Prior thereto, President and Chief Executive Officer of GLJ Petroleum Consultants Ltd.	Chairman
Michael Robert Culbert ⁽¹⁾ Calgary, Alberta Canada	President & Chief Executive Officer of Progress Energy Resources Corp. Prior thereto, President and Chief Executive Officer of Progress Energy Trust Prior thereto, Chief Executive Officer of Progress Energy Trust	Director
Bruce A. Francis ^{(2),(5)} Calgary, AB Canada	President of C3 Resources Ltd. Prior thereto, President of C2 Energy Inc.	Director

Name and Place of Residence	Principal Occupation During The Last Five Years	Position Held with the Corporation
Robert G. Peters ^{(3),(4)} Calgary, AB Canada	President of Black Diamond Land & Cattle Company Ltd.	Director

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Reserves Committee.
- (3) Member of the Compensation Committee.
- (4) Member of Corporate Governance Committee.
- (5) Member of Health, Safety and Environment Committee.
- (6) Chairman of the Board of Directors of Seaview.

Michael J.J. Wuetherick has been a director of Seaview since December 13, 2006, Messrs. Oldale, Turnbull, Howe, VanSickle and Gilbert have been directors of Seaview since June 15, 2007, Mr. Culbert has been a director since June 26, 2008 and Mr. Francis has been a director since July 24, 2008. Mr. Peters has been a director since May 2, 2008. The term of office of all directors will expire at the next annual meeting of the shareholders of Seaview.

As of April 6, 2011 the directors, officers and senior management of the Corporation, as a group, beneficially own, directly or indirectly 16,884,807 Class A Shares of the Corporation and 109,800 Class B Shares of the Corporation, or approximately 26% of the issued and outstanding Class A Shares and 10% of the issued and outstanding Class B Shares.

Each of Messrs. Wuetherick, Oldale, Campbell and Chandler and Ms. Bunch devotes his or her full time and attention to the business and affairs of Seaview. The other directors of Seaview will devote their time and attention to the affairs of Seaview as required.

Cease Trade Orders

Other than as described below, no director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of Seaview is, as of the date of this Annual Information Form, or has been, within the last 10 years, been a director or executive officer of any company (including Seaview) that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the company access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been 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 that person.

Gregory G. Turnbull, Q.C.

Mr. Turnbull was a director of Action Energy Inc., a corporation engaged in the exploration, development and production of oil and gas in Western Canada. Action Energy Inc. was placed into receivership on October 28, 2009 by its major creditor and Mr. Turnbull resigned as a director immediately thereafter.

Mr. Turnbull was a director of Mobilift Inc., a corporation engaged in the development, system integration and commercialization of innovative fall prevention technology. Mobilift Inc. was placed into receivership in September, 2001 by its major creditor after Mr. Turnbull left the board in August, 2001.

Daryl Gilbert

Mr. Gilbert was a director of Global Direct Inc. (“**Global**”) from May 1998 until the present. On November 20, 2002 and November 22, 2002 the British Columbia Securities Commission and the Alberta Securities Commission, respectively, issued cease trade orders because of the company’s failure to file its financial statements. The required financial statements were filed and the cease trade orders were revoked on December 23, 2002.

On June 12, 2007, the Court of Queen's Bench of Alberta granted an initial order to Global for creditor protection under the *Companies' Creditors Arrangement Act*. Such protection expired on December 7, 2007, the monitor was discharged on December 12, 2007 and a receiver manager was appointed.

Sanjib Gill

Mr. Gill was the Corporate Secretary of Action Energy Inc., a corporation engaged in the exploration, development and production of oil and gas in Western Canada. Action Energy Inc. was placed into receivership on October 28, 2009 by its major creditor and Mr. Gill resigned as the Corporate Secretary immediately thereafter.

Penalties or Sanctions

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of Seaview, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Personal Bankruptcies

No director, executive officer or shareholder holding a sufficient number of securities to affect materially the control of Seaview, or a personal holding company of any such persons, has, within the 10 years preceding the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being 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 individual.

Conflicts of Interest

Circumstances may arise where members of the board of directors of the Corporation are directors or officers of corporations which are in competition to the interests of the Corporation. No assurances can be given that opportunities identified by such board members will be provided to the Corporation. There are potential conflicts of interest to which the directors and officers of Seaview will be subject in connection with the operations of Seaview. In particular, certain of the directors and officers of Seaview are involved in managerial and/or director positions with other oil and gas companies and trusts whose operations may, from time to time, be in direct competition with those of Seaview or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Seaview. Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that 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 by the ABCA. Messrs. Oldale disclosed his interest in the 1332915 Acquisition to the Board and abstained from voting on all matters related to the 1332915 Acquisition.

PROMOTERS

Messrs. Wuetherick and Oldale are considered to be promoters of the Corporation in that they took the initiative in founding and organizing the Corporation. Messrs. Wuetherick and Oldale currently own or control 4,185,080 Class A Shares (6%) and own or control 31,500 Class B Shares (3%). Messrs. Wuetherick and Oldale have 870,000 and 786,000 options to purchase Class A Shares outstanding, respectively.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Corporation, there are no legal proceedings or regulatory actions material to the Corporation to which the Corporation is a party, or was a party to in 2010, or of which any of its properties is the subject matter, or was the subject matter of in 2010, nor are there any such proceedings known to the Corporation to be contemplated. There have been no penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority and the Corporation has not entered to any settlement agreements with a court or securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed elsewhere herein, none of the directors, officers or principal shareholders of Seaview, and no associate or affiliate of any of them, has or has had any material interest in any transaction which materially affects Seaview or any of its affiliates, other than H. Scott Oldale, Vice President, Exploration, Chief Operating Officer and a director of the Corporation, who holds 2,411,188 Class A Shares, representing 3.6% of the issued and outstanding Class A Shares. Seaview acquired 1332915 pursuant to the 1332915 Acquisition Agreement. See “*General Description of the Business*” for a more detailed description of the 1332915 Acquisition.

TRANSFER AGENT AND REGISTRAR

Transfer agent and registrar for the Class A Shares and the Class B Shares of the Corporation is Olympia Trust Company at its office in Calgary, Alberta.

MATERIAL CONTRACTS

Seaview did not enter into any material contracts during the most recently completed financial year or, before the most recently completed financial year, that are still in effect.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under NI 51-102 - *Continuous Disclosure Obligations* by the Corporation during, or related to, the Corporation’s most recently completed financial year other than Sproule, the Corporation’s independent engineering evaluator. As at the date hereof, to the knowledge of management of the Corporation, none of the aforementioned persons or companies, or principals thereof, had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation 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.

In addition, the financial statements of Seaview for the year ended December 31, 2010 were audited by KPMG LLP. KPMG LLP is independent in accordance with the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

AUDIT COMMITTEE

The purpose of Seaview’s Audit Committee is to provide assistance to the Board of Directors of Seaview in fulfilling its legal fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Corporation. It is the objective of the Audit Committee to maintain a free and open means of communications among the Board of Directors of Seaview, the independent auditors and the financial and senior management of the Corporation.

The full text of the Audit Committee’s Charter is included as Appendix “C” to this Annual Information Form.

Composition of the Audit Committee

The Audit Committee is comprised of James B. Howe, Steven R. VanSickle and Michael R. Culbert. The Chairman of the Audit Committee is Mr. Howe. Each of the members of the Audit Committee is financially literate under Section 1.5 of Multilateral Instrument 52-110 (“**MI 52-110**”). All members of the Audit Committee are independent as such term is described under Section 1.4 of MI 52-110.

Relevant Education and Experience

James B. Howe

Mr. Howe is a director of Seaview. Mr. Howe is a Chartered Accountant and has been the President of Bragg Creek Financial Consultants Ltd. since 1982. Mr. Howe is a director of various public companies including Pason Systems Ltd., Ensign Energy Services Ltd., Wrangler West Energy Inc., Bengal Energy Inc. and Holloway Lodging Real Estate Investment Trust. Mr. Howe has been Vice President, Finance of numerous publicly traded companies as well, including Canrise Resources Ltd., Bonavista Petroleum Ltd., Kintail Energy Inc., Nycan Energy Corp., and Kinloch Resources Inc.

Mr. Howe graduated from the University of Western Ontario with a Bachelor of Arts (Honours) in Business Administration in 1973.

Steven R. VanSickle

Mr. VanSickle is a director of Seaview. Mr. VanSickle has an extensive background in the oil and gas industry both in Canada and internationally. Mr. VanSickle has been involved in exploration, production, strategic planning and portfolio management in the oil and gas industry for the past 25 years.

From 2005, Mr. VanSickle has been the President and Chief Executive Officer of Fairborne Energy Ltd. From 2002 to 2005, Mr. VanSickle was the Vice President, Exploration of Fairborne Energy Ltd., the predecessor of Fairborne Energy Trust. From 1999 to 2002, Mr. VanSickle was part of the executive team which founded Canadian Midstream Services Ltd. and was Vice President, Business Development until the company was sold to Duke Energy Field Services in the spring of 2001. Mr. VanSickle was the Vice President of Business Development for Duke Energy Field Services in Canada.

Mr. VanSickle began his career as an exploration geologist with Amoco Canada in Calgary. In 1992-93, Mr. VanSickle attended Amoco's Petrophysics training school in Tulsa, Oklahoma and in 1995 was transferred to Houston, where he held a variety of positions, including Exploration Coordinator – Trinidad and Exploration Manager – Angola. In 1998, Mr. VanSickle joined Pan East Petroleum Corp. which was sold in November 1998.

Mr. VanSickle received his B.Sc. in Geology from McMaster University in 1986 and attended the Kellogg Executive Development Program in 1997.

Michael Robert Culbert

Mr. Culbert holds a Bachelor of Science Degree in Business Administration and has over twenty five years of diverse experience in the oil and gas industry including a background in marketing, business development, and economics and planning. Mike has held senior managerial and executive positions with a number of Calgary, Alberta based companies.

He is currently President & Chief Executive Officer, Progress Energy Resources Corp., a mid-size energy company primarily focused on natural gas exploration, development and production in northwest Alberta and northeast British Columbia. Prior to his current position, Mr. Culbert was the President & Chief Executive Officer of Progress Energy Ltd., a sustainability focused energy trust and prior to that was Vice President of Marketing and Business Development of Progress Energy Ltd., which he and two partners recapitalized in November of 2001.

Mr. Culbert is also well known in the North American capital markets as a result of his previous role as Vice President of Marketing and Business Development of Calgary based Encal Energy Ltd. ("**Encal**"), a Canadian senior producer listed on both the Toronto and New York Exchanges.

Audit Committee Oversight

Since the commencement of the Corporation's most recently completed financial year, there has not been a recommendation of the Audit Committee to nominate or compensate an external auditor which was not adopted by the Corporation's Board.

Reliance on Certain Exemptions

Since the commencement of the Corporation's most recently completed financial year, it has not relied on the exemption in section 2.4 (*De Minimus Non-audit Services*) or an exemption granted under Part 8 (*Exemptions*) from NI 52-110. The Corporation is a "venture issuer" as defined in NI 52-110 and is relying on the exemption contained in section 6.1 of NI 52-110, which exempts it from the requirements of Part 3 (*Composition of Audit Committee*) and Part 5 (*Reporting Obligations*) of NI 52-110.

Pre-Approval Policies and Procedures

The Audit Committee has adopted specific policies and procedures for the engagement of non-audit services whereby any financial services in excess of \$10,000 and outside the audit plan of the Corporation's auditors must be approved by the Chairman of the Audit Committee and the Board and Vice President, Finance and Chief Financial Officer of the Corporation. See the *Other Responsibilities* provisions of the Audit Committee Charter attached as Appendix C to this Annual Information Form.

External Auditor Service Fees

The fees paid to the Corporation's external auditor in each of the last two fiscal years are as follows:

Financial Year Ending	Audit Fees ⁽¹⁾	Audit-Related Fees ⁽²⁾	Tax Fees ⁽³⁾	All Other Fees ⁽⁴⁾
December 31, 2010	\$85,000	\$51,100	\$56,000	-
December 31, 2009	\$80,000	\$36,000	\$51,850	\$55,000

Notes:

- (1) The aggregate fees billed by the Corporation's auditor for audit fees.
- (2) The aggregate fees billed for assurance and related services by the Corporation's auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not disclosed in the "Audit fees" column.
- (3) The aggregate fees billed for professional services rendered by the Corporation's auditor for tax compliance, tax advice, and tax planning.
- (4) The aggregate fees billed for professional services rendered by the Corporation's auditor in relation to private placements, prospectus filings and the filing of Business Acquisition Reports.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Class A Shares and Class B Shares and securities authorized for issuance under equity compensation plans, is contained in the Corporation's Information Circular for the most recent annual meeting of shareholders that involved the election of directors.

Additional financial information is provided for in our financial statements and management's discussion and analysis for the year ended December 31, 2010. Documents affecting the rights of securityholders, along with other information relating to the Corporation, may be found on SEDAR at www.sedar.com and on the Corporation's website at www.seaviewenergy.com.

APPENDIX A

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

To the board of directors of Seaview Energy Inc. (the “**Company**”):

1. We have prepared an evaluation of the Company’s reserves data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company’s management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2010, and identifies the respective portion 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 (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
Sproule	Evaluation of the P&NG Reserves of Seaview Energy Inc. As of December 31, 2010, prepared December 2010 to February 2011	Canada				
Total			Nil	143,088	Nil	143,088

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

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after 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 Associated Limited, Calgary, Alberta, Canada, February 4, 2011.

(signed) "Gary R. Finnis"

Gary R. Finnis, P. Eng
Senior Petroleum Engineer and Associate

(signed) "Robert N. Johnson" for Eseoghene N. Omatsone

Eseoghene N. Omatsone, P.Eng, MBA
Senior Petroleum Engineer

(signed) "Marin L. Blair"

Maren L. Blair, P. Geol
Petroleum Geologist

(signed) "Harry J. Helwerda"

Harry J. Halwerda, P.Eng, FEC
Executive Vice-President and Director

APPENDIX B

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Terms to which a meaning is ascribed in National Instrument 51-101 have the same meaning herein.

Management of Seaview Energy Inc. (the “**Company**”) are responsible for the preparation and disclosure of information with respect to the Company’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of the proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

Independent qualified reserves evaluators have evaluated and reviewed the Company’s reserves data. The report of the independent qualified reserves evaluators is presented in the Annual Report of Seaview Energy Inc. for the year ended December 31, 2010.

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

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

The Reserves Committee of the Board of Directors has reviewed the Company’s procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with Management. The Board of Directors has, on the recommendation of the Reserves Committees 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(s) on the reserves data; and
- (c) the content and filing of this report.

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

(signed) "*Michael J.J. Wuetherick*"

Michael J.J. Wuetherick
President, Chief Executive Officer and Director

(signed) "*H. Scott Oldale*"

H. Scott Oldale
Vice President, Exploration, Chief Operating Officer and
Director

(signed) "*Daryl Gilbert*"

Daryl Gilbert
Director

(signed) "*Gregory Turnbull*"

Gregory Turnbull
Director

April 6, 2011

APPENDIX C

SEAVIEW ENERGY INC.

AUDIT COMMITTEE

TERMS OF REFERENCE

I. The Board of Directors' Mandate for the Audit Committee

1. *The Board of Directors* ("Board") has responsibility for the stewardship of Seaview Energy Inc. (the "Corporation"). To discharge that responsibility, the Board is obligated by the *Business Corporations Act* (Alberta) to supervise the management of the business and affairs of the Corporation. The Board's supervisory function involves Board oversight or monitoring of all significant aspects of the management of the Corporation's business and affairs.

Public financial reporting and disclosure by the Corporation are fundamental to the Corporation's business and affairs and to its status as a publicly listed enterprise. The objective of the Board's monitoring of the Corporation's financial reporting and disclosure is to gain reasonable assurance of the following:

- (a) that the Corporation complies with all applicable laws, regulations, rules, policies and other requirements of governments, regulatory agencies and stock exchanges relating to financial reporting and disclosure;
- (b) that the accounting principles, significant judgements and disclosures which underlie or are incorporated in the Corporation's financial statements are appropriate in the prevailing circumstances;
- (c) that the Corporation's quarterly and annual financial statements are accurate within a reasonable level of materiality and present fairly the Corporation's financial position and performance in accordance with generally accepted accounting principles; and
- (d) that appropriate information concerning the financial position and performance of the Corporation is disseminated to the public in a timely manner in accordance with corporate and securities law and with stock exchange regulations.

The Board is of the view that monitoring of the Corporation's financial reporting and disclosure policies and procedures cannot be reliably met unless the following activities ("the Fundamental Activities") are, in all material respects, conducted effectively:

- (i) the Corporation's accounting functions are performed in accordance with a system of internal financial controls designed to capture and record properly and accurately all of the Corporation's financial transactions and consistent with internal financial controls implemented by companies of similar size and peer group as the Corporation;
- (ii) the internal financial controls are regularly assessed for effectiveness and efficiency consistent with assessments performed by companies of similar size and peer group as the Corporation;
- (iii) the Corporation's quarterly and annual financial statements are properly prepared by management to comply with GAAP;
- (iv) the Corporation's quarterly and annual financial statements are reported on by an external auditor appointed by the shareholders of the Corporation.

To assist the Board in its monitoring of the Corporation's financial reporting and disclosure and to conform to applicable corporate and securities law, the Board has established the Audit Committee (the "Committee") of the Board.

2. *Composition of Committee*

- (a) The Committee shall be appointed annually by the Board and consist of at least three members from among the directors of the Corporation, each of whom shall be an independent director (as determined under applicable laws). Officers of the Corporation, who are also directors, may not serve as members of the Committee;
- (b) The Board shall designate the Chairman of the Committee;
- (c) In the event of a vacancy arising in the Committee or a loss of independence of any member, the Committee will fill the vacancy within six months or by the following annual shareholders' meeting if sooner.

3. *Reliance on Experts*

In contributing to the Committee's discharging of its duties under this mandate, each member of the Committee shall be entitled to rely in good faith upon:

- (a) financial statements of the Corporation represented to him by an officer of the Corporation or in a written report of the external auditors to present fairly the financial position of the Corporation in accordance with generally accepted accounting principles; and
- (b) any report of a lawyer, accountant, engineer, appraiser or other person whose profession lends credibility to a statement made by any such person.

4. *Limitations on Committee's Duties*

In contributing to the Committee's discharging of its duties under Terms of Reference, each member of the Corporation shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in these Terms of Reference is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is monitoring and reviewing to *endeavor to* gain reasonable assurance (but not to ensure) that the Fundamental Activities are being conducted effectively and that the objectives of the Corporation's financial reporting are being met and to enable the Committee to report thereon to the Board.

II. **Audit Committee Terms of Reference**

The Committee's Terms of Reference outlines how the Committee will satisfy the requirements set forth by the Board in its mandate. Terms of Reference reflect the following:

- Operating Principles;
- Operating Procedures;
- Specific Responsibilities and Duties.

A. *Operating Principles*

The Committee shall fulfill its responsibilities within the context of the following principles:

1) **Committee Values**

The Committee expects the management of the Corporation to operate in compliance with corporate policies; reflecting laws and regulations governing the Corporation; and to maintain strong financial reporting and control processes.

2) **Communications**

The Committee and members of the Committee expect to have direct, open and frank communications throughout the year with management, other Committee Chairmen, the external auditors, and other key Committee advisors or Corporation staff members as applicable.

3) **Financial Literacy**

All Committee Members should be sufficiently versed in financial matters to read and understand the Corporation's financial statements and also to understand the Corporation's accounting practices and policies and the major judgements involved in preparing the financial statements.

4) **Annual Audit Committee Work Plan**

The Committee, in consultation with management and the external auditors, shall develop an annual Committee work plan responsive to the Committee's responsibilities as set out in these Terms of Reference. In addition, the Committee, in consultation with management and the external auditors, shall participate in a process for review of important financial topics that have the potential to impact the Corporation's financial disclosure.

The work plan will be focused primarily on the annual and interim financial statements of the Corporation; however, the Committee may at its sole discretion, or the discretion of the Board, review such other matters as may be necessary to satisfy the Committee's Terms of Reference.

5) **Meeting Agenda**

Committee meeting agendas shall be the responsibility of the Chairman of the Committee in consultation with Committee members, senior management and the external auditors.

6) **Committee Expectations and Information Needs**

The Committee shall communicate its expectations to management and the external auditors with respect to the nature, timing and extent of its information needs. The Committee expects that written materials will be received from management and the external auditors at a reasonable time in advance of meeting dates.

7) **External Resources**

To assist the Committee in discharging its responsibilities, the Committee may at its discretion, in addition to the external auditors, at the expense of the Corporation, retain one or more persons having special expertise, including independent counsel.

8) **In Camera Meetings**

At the discretion of the Committee, the members of the Committee shall meet in private session with the external auditors. In addition, at the discretion of the Committee, the members of the Committee shall meet in private with the management of the Corporation, without the auditors being present at such meeting.

9) **Reporting to the Board**

The Committee, through its Chairman, shall report after each Committee meeting to the Board at the Board's next regular meeting.

10) **Committee Self Assessment**

The Committee shall annually review, discuss and assess its own performance. In addition, the Committee shall periodically review its role and responsibilities.

11) **The External Auditors**

The Committee expects that, in discharging their responsibilities to the shareholders, the external auditors shall report directly to and be accountable to the Board through the Committee. The external auditors shall report all material issues or potentially material issues, either specific to the Corporation or to the financial reporting environment in general, to the Committee.

B. *Operating Procedures*

- 1) The Committee shall meet at least four times annually, or more frequently as circumstances dictate. Meetings shall be held at the call of the Chairman, upon the request of two (2) members of the Committee or at the request of the external auditors.
- 2) A quorum shall be a majority of the members.
- 3) Unless the Committee otherwise specifies, the Secretary (or his or her deputy) of the Corporation shall act as Secretary of all meetings of the Committee.
- 4) In the absence of the Chairman of the Committee, the members shall appoint an acting Chairman.
- 5) A copy of the minutes of each meeting of the Committee shall be provided to each member of the Committee and to each director of the Corporation in a timely fashion.

C. *Specific Responsibilities and Duties*

To fulfill its responsibilities and duties, the Committee shall:

Financial Reporting

- 1) Review, prior to public release, the Corporation's annual and quarterly financial statements with management and the external auditors with a view to gaining reasonable assurance that the statements (i) are accurate within reasonable levels of materiality, (ii) complete, (iii) represent fairly the Corporation's financial position and performance in accordance with GAAP. The Committee shall report thereon to the Board before such financial statements are approved by the Board;
- 2) Receive from the external auditors reports of their review of the annual and quarterly financial statements and any management letters issued to the management of the Corporation;
- 3) Receive from management a copy of the representation letter provided to the external auditors and receive from management any additional representations required by the Committee;
- 4) Review, prior to public release, and, if appropriate, recommend approval to the Board, of news releases and reports to shareholders issued by the Corporation with respect to the Corporation's annual and quarterly financial statements;

- 5) Review and, if appropriate, recommend approval to the Board of prospectuses, material change disclosures of a financial nature, management discussion and analysis, annual information forms and similar disclosure documents to be issued by the Corporation; and
- 6) Review and validate procedures for the receipt, retention and resolution of complaints received by the Corporation from any party regarding accounting, auditing or internal controls. For greater certainty, the Committee's responsibilities in this area will not include complaints about minor operational issues. (Examples of minor operational issues include late payment of invoices, minor disputes over accounts owing or receivable, revenue and expense allocations and other similar items characteristic of the normal daily operations of the accounting department of an oil and gas company.)

Accounting Policies

- 1) Review with management and the external auditors the appropriateness of the Corporation's accounting policies, disclosures, reserves, key estimates and judgements, including changes or variations thereto.
- 2) Obtain reasonable assurance that they are in compliance with GAAP from management and external auditors and report thereon to the Board;
- 3) Review with management and the external auditors the apparent degree of conservatism of the Corporation's underlying accounting policies, key estimates and judgements and provisions along with quality of financial reporting.
- 4) Participate, if requested, in the resolution of disagreements, between management and the external auditors.
- 5) Review with management the categorization of flow-through expenditures and the qualification of such expenditures to satisfy the Corporation's existing obligations.

Risk and Uncertainty

- 1) Acknowledging that it is the responsibility of the Board, in consultation with management, to identify the principal business risks facing the Corporation, determine the Corporation's tolerance for risk and approve risk management policies, the Committee shall focus on financial risk and gain reasonable assurance that financial risk is being effectively managed or controlled by:
 - (a) reviewing with management the Corporation's tolerance for financial risks;
 - (b) reviewing with management its assessment of the significant financial risks facing the Corporation;
 - (c) reviewing with management the Corporation's policies and any proposed changes thereto for managing those significant financial risks;
 - (d) reviewing with management its plans, processes and programs to manage and control such risks.
- 2) Review policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;
- 3) Review foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments;
- 4) Review the adequacy of insurance coverages maintained by the Corporation;
- 5) Review regularly with management, the external auditors and the Corporation's legal counsel, any legal claim or other contingency, including tax assessments, that could have a material effect upon the financial position or

operating results of the Corporation and the manner in which these matters have been disclosed in the financial statements.

Financial Controls and Control Deviations

- 1) Review the plans of the external auditors to gain reasonable assurance that the evaluation and testing of applicable internal financial controls is comprehensive, coordinated and cost-effective;
- 2) Receive regular reports from management and the external auditors on all significant deviations or indications/detection of fraud and the corrective activity undertaken in respect thereto;
- 3) Institute a procedure that will permit any employee, including management employees, to bring to the attention of the Chairman of the Committee, under conditions of confidentiality, concerns relating to financial controls and reporting which are material in scope and which cannot be addressed, in the employee's judgement, through existing reporting structures in the Corporation;
- 4) Review, and periodically assess the adequacy of controls over financial information disclosed to the public, which is extracted or derived from the Corporation's financial statements.

Compliance with Laws and Regulations

- 1) Review regular reports from management and others (e.g. external auditors) with respect to the Corporation's compliance with laws and regulations having a material impact on the financial statements including:
 - (a) tax and financial reporting laws and regulations;
 - (b) legal withholding requirements;
 - (c) other laws and regulations which expose directors to liability;
- 2) Review the filing status of the Corporation's tax returns, flow-through share renunciation filings and those of its subsidiaries.

Relationship with External Auditors

- 1) Recommend to the Board the nomination of the external auditors;
- 2) Approve the remuneration and the terms of engagement of the external auditors as set forth in the Engagement Letter;
- 3) Review the performance of the external auditors annually or more frequently as required;
- 4) Receive annually from the external auditors an acknowledgement in writing that the shareholders, as represented by the Board and the Committee, are their primary client;
- 5) Receive a report annually from the external auditors with respect to their independence, such report to include a disclosure of all engagements (and fees related thereto) for non-audit services by the Corporation;
- 6) Review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, and the materiality levels which the external auditors propose to employ;

- 7) Meet with the external auditors in the absence of management to determine, inter alia, that no management restrictions have been placed on the scope and extent of the audit examinations by the external auditors or the reporting of their findings to the Committee;
- 8) Establish effective communication processes with management and the Corporation's external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, management and the Committee; and
- 9) Establish a reporting relationship between the external auditors and the Committee such that the external auditors can bring directly to the Committee matters that, in the judgement of the external auditors, merit the Committee's attention. In particular, the external auditors will advise the Committee as to disagreements between management and the external auditors regarding financial reporting and how such disagreements were resolved.

Other Responsibilities

- 1) Approve annually the reasonableness of the expenses of the Chairman of the Board and the Chief Executive Officer;
- 2) After consultation with the Chief Financial Officer and the external auditors, consider at least annually, of the quality and sufficiency of the Corporation's accounting and financial personnel and other resources;
- 3) Approve in advance non-audit services, including tax advisory and compliance services, provided by the external auditors. However, the Committee can establish a threshold amount for fees for non-audit services to be provided by the external auditors without advance approval of the Committee. The nature of such services and the associated cost will be provided to the Committee at the next following meeting.
- 4) Investigate any matters that, in the Committee's discretion, fall within the Committee's duties;
- 5) Perform such other functions as may from time to time be assigned to the Committee by the Board.
- 6) Review and update the Terms of Reference on a regular basis for approval by the Board; and
- 7) The Committee will review disclosures regarding the organization and duties of the Committee to be included in any public document, including quarterly and annual reports to shareholders, information circulars and annual information forms.