

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2014

April 30, 2015

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CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**ABCA**" means *Business Corporations Act* (Alberta);

"**BCBCA**" means *Business Corporations Act* (British Columbia);

"**Cawley**" means Cawley, Gillespie and Associates Inc., independent reserves engineers;

"**Cawley Report**" has the meaning ascribed thereto under "*Oil and Gas Information – Statement of Reserves Data and Other Oil & Gas Information*";

"**Mountainview**", the "**Corporation**", "**we**", "**us**" or "**our**" means Mountainview Energy Ltd.;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means the common shares in the capital of Mountainview;

"**gross**" means:

(a) in relation to our interest in production and reserves, our "company gross" reserves, which are our working interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

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

(c) in relation to properties, the total area of properties in which we have an interest.

"**Medicine Lake Assets**" means certain oil and natural gas assets located in the Medicine Lake prospect in Divide County, North Dakota and Sheridan County, Montana, acquired by the Corporation in 2012 pursuant to the Transactions (as defined below);

"**net**" means:

(a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interests in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

(c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest we own.

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

"**NI 51-101 Report**" means the Corporation's Form 51-101F1 – *Statement of Reserves Data and Other Oil and Gas Information* dated April 11, 2014, which is incorporated by reference in this Annual Information Form under the heading "*Oil and Gas Information – Statement of Reserves Data and Other Oil and Gas Information*" and is available on SEDAR at www.sedar.com;

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

"**NI 52-110**" means National Instrument 52-110 – *Audit Committees*;

"**Options**" means options to purchase Common Shares granted to officers, directors, employees and consultants of the Corporation pursuant to the Corporation's stock option plan;

"**Pondera Assets**" means certain oil and gas assets located in the Williams and Lake Frances areas of Pondera County, Montana, acquired by the Corporation in 2012 pursuant to the Transactions (as defined below);

"**Pondera Equipment**" means certain compressor plant, related ancillary equipment and field wellhead equipment and pipelines related to the Pondera Assets;

"**Shareholders**" means the holders of Common Shares;

"**TSXV**" means the TSX Venture Exchange; and

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

ABBREVIATIONS

Oil and Natural Gas Liquids

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

Natural Gas

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

Other

CBM	means coalbed methane
BOE or boe	means barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
Mboe	means thousand barrels of oil equivalent
MMboe	means million barrels of oil equivalent
boe/d	means barrels of oil equivalent per day
WTI	means West Texas Intermediate
psi	means pounds per square inch

OIL AND GAS INFORMATION ADVISORIES

Where any disclosure of reserves data is made in this Annual Information Form that does not reflect all of the reserves of the Corporation, the reader should note that the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Disclosure provided herein in respect of BOEs or Mcfs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl and an Mcf conversion ratio of 1 bbl:6 Mcf are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf:1 bbl, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indication of value.

Any references in this Annual Information Form to initial, early and/or test or production/performance rates and/or "flush" production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for the Corporation. The initial production rate may be estimated based on other third party estimates or limited data available at this time. The initial production is generally estimated using BOEs. In all cases in this Annual Information Form initial production or test are not necessarily indicative of long-term performance of the relevant well or fields or of ultimate recovery of hydrocarbons.

Certain information in this Annual Information Form may constitute "analogous information" as defined in NI 51-101, including, but not limited to, information relating to areas, assets, wells and/or operations that are in geographical proximity to or believed to be on-trend with lands held by Mountainview. Such information has been obtained from public and government sources, regulatory agencies or other industry participants. Management of Mountainview believes the information may be relevant to help define the reservoir characteristics in which Mountainview may hold an interest and such information has been presented to help demonstrate the basis for Mountainview's business plans and strategies. However, management cannot confirm whether such analogous information has been prepared in accordance with NI 51-101 and the COGE Handbook or prepared by a qualified reserves evaluator or auditor. Mountainview has no way of verifying the accuracy of such information. There is no certainty that the results of the analogous information or results inferred thereby will be achieved by Mountainview and such information should not be construed as an estimate of future production levels or the actual characteristics and quality of Mountainview's assets. Such information is also not an estimate of the reserves or resources attributable to lands held or to be held by Mountainview and there is no certainty that such information will prove to be analogous in the future. **The reader is cautioned that the data relied upon by Mountainview may be in error and/or may not be analogous to such lands to be held by Mountainview.**

CONVERSIONS

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
Gigajoules	MMbtu	0.950

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2014.

This Annual Information Form contains references to Canadian dollars and U.S. dollars. All dollar amounts referenced, unless otherwise indicated, are expressed in Canadian dollars. References to "Canadian dollars",

"CDN$" or "$" are to the currency of Canada and references to "U.S. dollars" or "US$" are to the currency of the United States, unless otherwise indicated.

The following table sets forth: (i) the rates of exchange for Canadian dollars, expressed in United States dollars, in effect at the end of each of the periods indicated; and (ii) the high, low and average exchange rates during each such period, in each case, based on these rates published on the Bank of Canada's website as being in effect at approximately noon on each trading day (the "**Bank of Canada Noon Rate**").

	Year Ended December 31,		
	2014	2013	2012
Rate at end of Period	US$0.8620	US$0.9402	US$1.0051
Average rate during Period	US$1.1045	US$0.9710	US$1.0004
High	US$0.9422	US$1.0164	US$1.0299
Low	US$0.8589	US$0.9348	US$0.9599

On April 30, 2015, the Bank of Canada Noon Rate for CAD$1.00 was US$0.8252.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained in this Annual Information Form, and in the documents incorporated by reference herein, contain forward-looking statements. In particular, and without limitation, this Annual Information Form contains forward-looking statements pertaining to the following:

- the performance characteristics and quality of the Corporation's properties;
- anticipated production levels;
- the quantity of the Corporation's reserves;
- net present values of future net revenues from the Corporation's reserves;
- projections of market prices for crude oil, natural gas and natural gas liquids and the impact of changes in commodity prices on the Corporation's cash flows;
- projections of anticipated costs for exploration, development, operations, production, abandonment and reclamation for the Corporation;
- the anticipated capital expenditure program for the Corporation and sources of funding of the capital expenditure program;
- the ability of the Corporation to achieve drilling success consistent with management's expectations;
- supply and demand fundamentals for commodities;
- realization of anticipated benefits of acquisitions or dispositions;
- plans for, and results of, exploration and development activities;
- business plans, growth strategy and opportunities;
- the source of funding for the Corporation's activities;
- treatment under governmental regulatory regimes and tax laws;
- the timing for, and cost of, additional development drilling, and the timing for, and levels of, increases to production and reserves;
- the development risk and exploitation potential of assets and properties owned by the Corporation;
- expectations regarding the ability of the Corporation to raise capital and to continually acquire reserves through acquisitions and development;
- access to, and sufficiency of, credit facilities and related borrowing base capacity;
- hedging activities of the Corporation;
- access to capital markets and availability and sufficiency of funding for growth and acquisition opportunities; and
- control of capital spending pursuant to joint operating agreements and similar operating arrangements.

Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Mountainview believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Mountainview can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Mountainview operates; the timely receipt of any required regulatory approvals; the ability of Mountainview to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of Mountainview and/or the operators of the projects in which Mountainview has an interest, to operate in a safe, efficient and effective manner; the ability of Mountainview to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development or exploration; the timing and costs of pipeline, storage and facility construction and expansion; the ability of Mountainview to secure adequate product transportation and marketing services; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Mountainview operates; and the ability of Mountainview to successfully market its oil and natural gas products.

Forward-looking statements involve significant risks and uncertainties. The Corporation's actual results could differ materially from those anticipated in forward-looking statements as a result of the risk factors set forth below and included elsewhere in this Annual Information Form:

- failure to achieve success in its planned drilling program and, in particular, to achieve the Corporation's expected working interest production;
- failure to realize the anticipated benefits of the assets and properties owned by the Corporation and future acquisitions;
- unforeseen difficulties in integrating future acquisitions into the Corporation's operations;
- risks associated with reservoir performance;
- volatility of costs of development, operations and maintenance of properties;
- general economic, market and business conditions;
- volatility of market prices for crude oil, natural gas and natural gas liquids and the marketability and hedging activities related thereto;
- risks related to the exploration, development and production of crude oil, natural gas and natural gas liquids reserves and resources;
- risks which may create liabilities to the Corporation in excess of its insurance coverage;
- current global financial conditions, including fluctuations in interest rates, foreign exchange rates, inflation, commodity prices and stock market volatility;
- uncertainties associated with estimating crude oil, natural gas and natural gas liquids, reserves and cash flows to be derived therefrom;
- competition for, among other things, capital, acquisitions of resources and reserves, undeveloped or underdeveloped lands and skilled personnel;
- political or economic developments;
- liabilities inherent in oil and natural gas operations;
- the results of litigation or regulatory proceedings that may be brought against the Corporation;
- fluctuations in the cost of borrowing;
- incorrect assessments of the value of acquisitions and the likelihood of success of exploration and development programs;
- geological, technical, drilling and processing problems, including the availability of equipment and access to properties;
- environmental risks and hazards;
- changes in tax laws and incentive programs relating to the oil and natural gas industry;
- changes in government regulations;
- the use of derivative financial instruments;
- failure to obtain regulatory, industry partner and/or third party consents and approvals where required;
- failure to engage or retain key personnel;

- claims made in respect of the Corporation's properties or assets;
- potential losses which would stem from any disruptions in production, including work stoppages or other labour difficulties, or disruptions in the transportation network on which the Corporation is and will be reliant;
- potential delays or changes in plans with respect to exploration or development projects or capital expenditures;
- failure of the Corporation to meet specific requirements of its leases or agreements;
- failure to accurately estimate abandonment and reclamation costs;
- the ability to obtain financing on acceptable terms;
- failure of third parties' reviews, reports and projections to be accurate;
- the occurrence of unexpected events; and
- other factors discussed under "*Risk Factors*".

The recovery and reserve estimates of Mountainview's reserves provided herein, and in the documents incorporated by reference herein, are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Mountainview's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and Mountainview assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein, and in the documents incorporated by reference herein, concerning the oil and gas industry and Mountainview's general expectations concerning the industry, are based on estimates prepared by management using data from public and government sources, regulatory agencies or other industry sources, as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry, which Mountainview believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market position, market share and performance characteristics. While Mountainview is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

BACKGROUND

General

Mountainview was incorporated in the Province of British Columbia under the *Company Act* (British Columbia) on May 31, 2000, was subsequently transitioned to the BCBCA and was continued into the Province of Alberta under the ABCA on May 24, 2012.

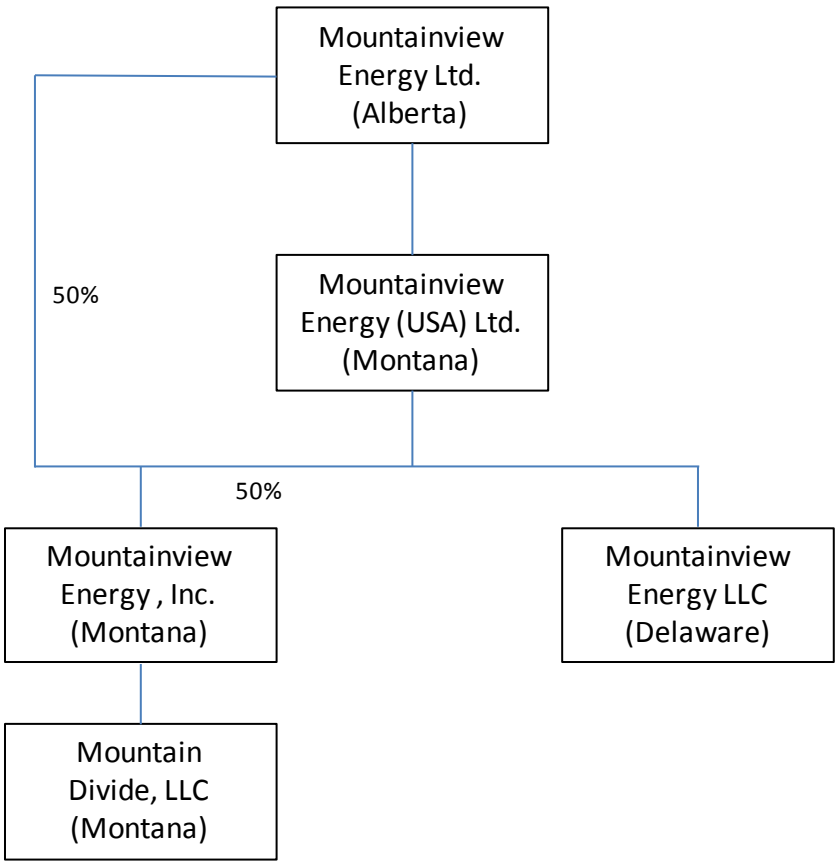
Mountainview's principal business is the exploration, acquisition, development and production of petroleum and natural gas reserves in the State of Montana and the State of North Dakota, USA.

Mountainview's head office is located at P.O. Box 200, 33 First Avenue SW, Cut Bank, Montana, USA 59427-0200, and its registered office is located at 2400, 525 – 8th Avenue SW Calgary, Alberta, Canada T2P 1G1.

The Common Shares trade on the TSXV under the symbol "MVW".

Intercorporate Relationships

The material subsidiaries of the Corporation are set forth below: **[NTD: add additional figures to reflect ownership of voting securities of each subsidiary]**



Note:

1. The Corporation, directly or indirectly through wholly-owned subsidiaries, owns all of the issued and outstanding Class A common shares of Mountainview Energy (USA) Ltd. Altamont Energy, Inc., an entity controlled by Patrick Montalban, President and Chief Executive Officer and a director of the Corporation, owns 7,822,727 Class B common shares of Mountainview Energy (USA) Ltd., which are convertible in accordance with their terms into Common Shares on a one for one basis and which, upon such conversion into Common Shares, would represent approximately 8.9% of the issued and outstanding Common Shares as at April 16, 2015.

GENERAL DEVELOPMENT OF OUR BUSINESS

The following is a summary description of the development of our business since January 1, 2012.

Year ended December 31, 2012

On January 19, 2012, the Corporation entered into a series of definitive agreements to consummate the direct and indirect acquisitions of the Pondera Assets, the Pondera Equipment and the Medicine Lake Assets (collectively, the "**Transactions**").

On May 14, 2012, after receiving Shareholder approval, Mountainview completed the Transactions and continued into the Province of Alberta under the ABCA.

On November 5, 2012, Mountainview entered into a $75.0 million senior secured advancing line credit facility with a major energy capital provider. In connection with the credit facility, Mountainview assigned 12,579 net acres of oil and gas leaseholds located in Divide County, North Dakota in what the Corporation calls its "12 Gage project" to Mountain Divide, LLC, a wholly-owned subsidiary of the Corporation. See "*Borrowings*" in this Annual Information Form.

Year ended December 31, 2013

In 2013, Mountainview focused on the development of its 12 Gage project in Divide County, North Dakota. Mountainview successfully drilled eight wells (4.8 net) in the 12 Gage project in 2013, completing six wells (3.4 net) prior to year end. The wells were all drilled targeting the Three Forks/Torquay formation. The six completed wells were producing at year end.

Year ended December 31, 2014

During the year ended December 31, 2014, Mountainview completed the two wells (1.4 net) that were drilled in late 2013 in Divide County, North Dakota. These wells were brought on to production in February, 2014. In the third quarter of 2014, the Company successfully drilled an additional three wells (1.3 net), all targeting the Three Forks/Torquay formation. One of the wells (0.6 net) was completed in the fourth quarter of 2014 and was producing at year end. This well brought the number of producing wells in the Company’s 12 Gage project to nine (5.4 net).

Mountainview was unsuccessful in its efforts to seek financing in 2014, through equity and/or refinancing its debt, despite the repeated efforts of management and the Board.

Subsequent to December 31, 2014

Mountainview has encountered difficulty in raising capital to fund its operations and to meet its obligations as they become due. Mountain Divide, LLC ("Divide"), an indirect wholly-owned subsidiary of the Corporation, holds the assets comprising the Corporation's core 12 Gage project in Divide County, North Dakota. Pursuant to the terms of Divide's senior secured advancing credit facility (the "Credit Facility") with Wells Fargo Energy Capital, Inc. (the "Lender"), the terms of the Credit Facility are such that, subject to certain shared costs, currently 85% of net revenue from the 12 Gage project, which is Divide and the Corporation's principal source of revenue, is automatically held back by the Lender to service amounts owing under the Credit Facility, which, when combined with the low commodity price environment and the difficulties Mountainview has encountered to raise capital, has left Divide with limited cash to fund operations and service debt. Historically, the 85% net revenue sweep does not cover interest expenses, which creates a default under the Credit Facility; however, Divide has not obtained waivers from the Lender and, as such, is in default on this matter. In addition to the USD$50.5 million owed under the Credit Facility, the Corporation and its subsidiaries currently owe: (a) an aggregate of USD$10.7 million pursuant to outstanding promissory notes issued by major shareholders; (b) USD$2.3 million pursuant to an outstanding convertible debenture issued by a major shareholder; (c) USD $8.7 million owed under Mountain View U.S.'s credit facility with First Interstate Bank; and (d) USD$19.0 million in trade payables and accrued liabilities, which are primarily owed by Divide. In addition, several creditors of Divide have recorded liens against lands in the 12 Gage project, which has led to further financial difficulty and has caused Divide to be in breach of the Credit Facility.

Although current average daily corporate production is 714 boe/d (net, 86% liquids), the 85% net revenue sweep mechanism under the Credit Facility has put a significant strain on Mountainview's working capital position and the Corporation does not have sufficient funds to run a capital program at this time. Negotiations and discussions with the creditors have yet to fully resolve the issues facing the Corporation and its subsidiaries. As a result, the board of directors of the Corporation is considering all available alternatives, including, without limitation, debt refinancing, equity financing, asset sales and corporate sale transactions. The board will continue to explore available alternatives with a view to the best interests of the Corporation.

Significant Acquisitions

During the year ended December 31, 2014, Mountainview did not complete any "significant acquisitions" within the meaning of that term in NI 51-102.

DESCRIPTION OF BUSINESS

Business Plan and Growth Strategies

Mountainview's principal business is the exploration, acquisition, development and production of petroleum and natural gas reserves in the States of Montana and North Dakota. Mountainview's primary focus is on the exploration, production and development of the Bakken and Three Forks Shale in the Williston Basin and the South Alberta Bakken.

The business plan of Mountainview is to seek to create sustainable and profitable per share growth in reserves, production and cash flow in the oil and gas industry. To accomplish this, Mountainview has pursued an integrated growth strategy with active development, and exploration drilling within its core 12 Gage project area, together with the focused acquisition of additional acreage and working interests.

If it is able to secure additional financing, Mountainview intends to focus on exploration and development oil wells over the course of the next several years. From time to time Mountainview will consider asset and corporate acquisition opportunities that meet its business parameters.

In reviewing potential drilling or acquisition opportunities, Mountainview will use the most current methodologies in giving consideration to the following criteria:

- Mountainview's technical expertise in the opportunity;
- the amount of risk capital required to secure or evaluate the investment opportunity;
- the potential return on the investment, if successful;
- the likelihood of success; and
- risked return versus cost of capital.

Mountainview may, in its discretion, proceed with asset or corporate acquisitions, dispositions or investments that do not conform to the guidelines discussed above based upon its consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality. In addition, Mountainview may, from time to time, consider seeking joint venture partners, strategic investors or other business arrangements to help improve the balance sheet or aid in the development of its properties.

Mountainview's management team is comprised of a proven team of professionals in all key operational areas of the organization including a team experienced in providing organic growth through full cycle exploration, exploitation and development. See "*Directors and Officers*".

As at December 31, 2014, Mountainview and its subsidiaries had a total of **[16]** employees.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Mountainview competes with numerous other industry participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Mountainview's competitors include resource companies which have greater financial resources, staff

and facilities than those of Mountainview. Competitive factors in the distribution and marketing of oil and natural gas include price, method and reliability of delivery. Mountainview believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

OIL AND GAS INFORMATION

Statement of Reserves Data and Other Oil and Gas Information

The Form 51-101F1 – *Statement of Reserves Data and Other Oil and Gas Information* dated March 30, 2015 (attached hereto as Schedule "A"), the report of Cawley in the form of Form 51-101F2 - *Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor* dated March 30, 2015 (attached hereto as Schedule "B"), and the Form 51-101F3 - *Report of Management and Directors on Oil and Gas Disclosure* dated March 30, 2015 (attached hereto as Schedule "C"), were filed under the Corporation's profile at www.sedar.com. In accordance with NI 51-101, the reserves data of Mountainview as set forth in the Form 51-101F1 is based upon an independent evaluation by Cawley with an effective date of December 31, 2014 (the "**Cawley Report**").

Selected reserve information is outlined below and should be read in conjunction with Mountainview's Form 51-101F1, 51-101F2 and 51-103, respectively, and Mountainview's audited financial statements for the year ended December 31, 2014 and related management discussion and analysis, which is available for review under Mountainview's SEDAR profile at www.sedar.com.

Summary of Oil & Gas Reserves
As of December 31, 2014
Forecast Prices & Costs

	Reserves					
	Light and Medium Oil		Natural Gas		Total Barrels Oil Equivalent	
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved Developed Producing	1,697.4	1,414.2	1,554.0	1,264.2	1,956.4	1,624.9
Proved Developed Non-Producing	207.9	166.3	155.9	124.7	233.9	187.1
Proved Undeveloped	4,739.5	3,793.7	3,577.1	2,864.5	5,335.7	4,271.1
Total Proved	6,644.8	5,374.2	5,287.0	4,253.4	7,526.0	6,083.1
Total Probable	5,032.5	4.028.8	3,833.8	3,070.6	5,671.5	4,540.6
Total Proved Plus Probable	11,677.3	9,403.0	9,120.8	7,324.0	13,197.4	10,623.7

Summary of Net Present Values of Future Net Revenue
As of December 31, 2014
Forecast Prices and Costs

	Before Income Taxes Discounted At (%/year)					After Income Taxes Discounted At (%/year)					Before Tax Net Value
	0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	10%/yr ($/boe)
Proved Developed Producing	37,632	32,102	26.657	22,568	19,537	33,021	29,373	24,966	21,466	18,778	13.63
Proved Developed Non-Producing	5.052	3.535	2,623	2.022	1.593	4.194	3.059	2.341	1.844	1.474	11.21
Proved Undeveloped	72,647	34,653	14,888	3,948	-2,396	47,839	21,641	7,710	-114	-4,685	2.79
Total Proved	115,331	70,290	44,168	28,538	18,734	85,054	54,073	35,017	23,196	15,567	5.87
Total Probable	110,783	51,834	25,220	12,340	5,787	70,614	32,410	15,199	6,941	2,805	4.45
Total Proved Plus Probable	226,114	122,124	69,388	40,878	24,521	155,668	86,483	50,216	30,137	18,372	5.26

Note: All amounts are in US$.

Property Descriptions

The following property descriptions are as of December 31, 2014 unless otherwise noted, and reserves quoted are as reported in the Cawley Report.

Williston Basin, USA

12 Gage

Mountainview, through a subsidiary, owns a working interest in 6,087 gross (3,610 net) acres in the 12 Gage project located in Divide County, North Dakota. Mountainview's drilling program in 2014 consisted of three wells (1.3 net). The following table outlines the results of the 2014 drilling program at 12 Gage:

					Average Daily Rates (Gross)		
Well	**Spud Date**	**Completion Date**	**Lateral Length**	**Frac Stages**	**30 Day IP (boe/d)**	**60 Day IP (boe/d)**	**Current (boe/d)**
BJNJ 30-31-1H	8/16/2014	10/15/2014	9,468’	36	568	513	165
BJNJ 19-18N-1H	7/27/2014	N/A	10,100’	36 (planned)	N/A	N/A	N/A
AABERG 8-5N-1H	9/9/2014	N/A	10,030’	36 (planned)	N/A	N/A	N/A

Medicine Lake

The Medicine Lake area is comprised of certain non-operated oil and natural gas assets and undeveloped acreage located in Divide and Williams County, North Dakota and Roosevelt and Sheridan County, Montana, consisting of approximately 20,026 gross (4,935 net) acres of undeveloped land.

Mountainview holds a non-operated working interest in 19 wells in the Medicine Lake area, with those interests varying from as low as 1% to as high as 16.6%.

South Alberta Basin, USA

Red Creek

Mountainview owns a 100% working interest in approximately 2,500 net acres located within the Red Creek property, located in Glacier County, Montana. Mountainview intends to continue its workover and development program in this area, with a few existing wells to be brought back on stream. The Corporation plans to drill one to two wells per year to continue developing the field.

Lake Frances

The Lake Frances area is comprised of 37,830 gross (32,191 net) acres of petroleum and natural gas lands, of which 4,000 gross (3,750 net) acres have been developed with 25 gross (18.75 net) wells drilled on 160 acre spacing. The total acreage, including an undeveloped area totaling 33,830 gross (28,441 net) acres, is located in Pondera County, Montana. While the acreage is not all contiguous, it is anticipated that the development will continue on a 160 acre spacing basis. Development on this property is not expected to commence until there is an increase in the price of natural gas.

Williams

The Williams area is comprised of 18,273 gross (14,922 net) acres of petroleum and natural gas lands, of which 11,520 gross (11,520 net) acres have been developed with 18 gross (18 net) wells drilled on 640 acre spacing. The total acreage, including an undeveloped area encompassing 6,753 gross (3,402 net) acres, is located in Pondera County,

Montana. The acreage is relatively contiguous, and it is anticipated that development will continue, however development is expected to be effected on a 320 acre spacing basis rather than the existing 640 acre spacing. Development on this property will not commence until there is an increase in the price of natural gas.

Loneman Coulee

Effective August 31, 2010, the Corporation accepted assignment of all of Altamont Oil & Gas, Inc.'s right, title and interest in the Loneman Coulee located in Pondera County and consisting of 1,718 acres gross (40 net). Located within this acreage are four wells, which the Corporation then became the operator of. On the property, there is currently one producing oil well and one shut-in oil well. The remaining wells were converted to a water disposal system for handling the disposal of water for other operators developing the South Alberta Bakken.

Pondera

Mountainview entered into a farm-out agreement with Majestic Oil & Gas, Inc. on September 1, 2009, outlining parameters for Mountain View Energy, Inc., a wholly-owned subsidiary of Mountainview, to drill a test well in the NWSE-Section 33-T27N-R4W, Teton County, Montana at its sole cost, risk and expense. In doing so, Mountain View Energy, Inc., acquired 75% of the working interest, while Majestic Oil & Gas, Inc. retained a 25% working interest in any well drilled in the 40-acre tract.

Two wells were drilled and completed on this property in 2009 and both wells continue to produce to-date. The acreage is held by production and is prospective for future development.

Snoose Coulee

Effective April 1, 2010 the Corporation acquired 100% of a third party's 30% right, title and interest in the Snoose Coulee Field located in Liberty County, Montana for $55,000. Included with this acquisition was a working and royalty interest in 14 gross (4.29 net) natural gas wells.

The following table sets forth the number and status of wells in which the Corporation held a working interest as at December 31, 2014:

	Oil Wells		**Natural Gas Wells**	
	Gross	**Net**	**Gross**	**Net**
12-Gage				
Producing	9.0	7.2	-	-
Non-Producing	2.0	.7	-	-
Red Creek				
Producing	35.0	35.0	-	-
Non-producing	3.0	3.0	-	-
Williams				
Producing	-	-	17.0	17.0
Non-Producing	-	-	1.0	1.0
Lake Frances				
Producing	-	-	25.0	18.8
Non-Producing	-	-	-	-
Loneman Coulee				
Producing	1.0	.5	-	-
Non-Producing	1.0	.5	-	-
Pondera/Donovan				
Producing	2.0	1.5	-	-
Non-Producing	-	-	-	-
Snoose Coulee				
Producing	-	-	13.0	4.3
Non-Producing	-	-	1.0	.3
Medicine Lake				
Producing	19.0	.6	-	-
Non-Producing	-	-	-	-
TOTALS:	72.0	49.0	57.0	41.4

DIVIDENDS

Mountainview has not paid any dividends on its outstanding Common Shares and the board of directors of Mountainview (the "**Board of Directors**") has determined not to pay any dividends on the Common Shares at the present time. Any future decision to pay dividends, including the actual timing, payment and amount of dividends, if any, will be made by the Board of Directors based upon, among other things, the cash flow, results of operations and financial conditions of Mountainview, the need for funds to finance ongoing operations and other business considerations as the Board of Directors considers relevant. Mountainview's current credit facility does not permit payment of dividends on the outstanding Common Shares.

DESCRIPTION OF SHARE CAPITAL

Mountainview is authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of Common Shares are entitled to one vote per share at meetings of Shareholders except meetings at which only holders of a specified class of shares are entitled to vote. Shareholders are entitled to one vote for each Common Share held. Subject to the rights, privileges, restrictions and conditions attaching to any prior ranking shares, the Common Shares rank equally as to dividends, voting rights, and any distribution of remaining assets on winding up or liquidation. There are no pre-emptive, redemption, or conversion rights attached to the Common Shares.

Mountainview is also authorized to issue an unlimited number of preference shares without nominal or par value in one or more series at any time, or from time to time, with such rights, privileges, restrictions and conditions as the Board of Directors may determine. The shares of each series of preference shares, if, as and when issued, will be entitled to a preference over the Common Shares and over any other shares of Mountainview ranking junior to the preference shares with respect to priority in payment of dividends, distribution of assets, or return of capital in the event of liquidation, dissolution or winding-up, whether voluntary or involuntary, or any other return of capital or distribution of assets among shareholders for the purpose of winding-up the affairs of the Corporation. The preference shares of each series participate rateably with the preference shares of all other series in respect of all accumulated dividends, whether or not declared and all declared non-cumulative dividends. The preference shares of each series rank on a parity with the preference shares of every other series with respect to priority in payment of dividends and in return of capital in the event of liquidation, dissolution or winding-up. The holders of preference shares will have the right to attend and vote at meetings of shareholders or shall be subject to such restrictions on attendance or voting rights thereat as may be determined by resolution of the Board of Directors.

MARKET FOR SECURITIES

The Common Shares are listed and trade on the TSXV and trade under the symbol "MVW". The following table sets forth the price range and trading volume of the Common Shares on the TSXV for the periods indicated.

Period	High ($)	Low ($)	Volume
2014			
January	0.55	0.44	819,996
February	0.55	0.445	493,421
March	0.64	0.47	695,112
April	0.60	0.49	404,623
May	0.55	0.405	364,833
June	0.495	0.35	813,135
July	0.50	0.425	439,571
August	0.455	0.39	299,517
September	0.40	0.34	198,017
October	0.35	0.285	804,670
November	0.325	0.235	520,641
December	0.295	0.08	1,257,379
2015			
January	0.145	0.06	722,306
February	0.09	0.04	2,751,107
March	0.09	0.025	710,208
April (1 to 29)	0.05	0.025	381,453

PRIOR SALES

The Corporation issued the following securities during the most recently completed financial year.

Security	Date of Issue	Aggregate Number Issued	Price (C$)
Common Shares	-	-	N/A
Options	-	-	N/A

ESCROWED SECURITIES

There are no securities of the Corporation currently held in escrow.

BORROWINGS

Line of Credit

On April 17, 2012, the Company entered into a revolving line of credit for $5,500,000 and on June 27, 2012, increased the line of credit to $8,700,000. During the year ended December 31, 2014, the line of credit was converted to a term loan extending the maturity date from October 17, 2014 to November 1, 2015. The outstanding balance at December 31, 2014 was $8,660,000. The Company's US subsidiary provided a general security over its assets as collateral for the line of credit and, a director and officer of the Company and major shareholder have provided personal guarantees. Carrying value of the collateral at December 31, 2014 was $4,060,588. The minimum interest rate is 5.25%. Repayment terms are monthly principal and interest payments of $110,900. At December 31, 2014 the Company was in default due to nonpayment of a lump sum principal payment due December 1, 2014. The Company has also not made payments on the loan in the months of February and March 2015. At this time the bank has not taken any formal action to exercise its rights and/or remedies under the credit agreement, nor has it applied the Default Rate. The Company continues to communicate with the bank and is currently engaged in negotiations with the bank to reach a solution that would allow for repayment terms that would rectify the defaults, while still providing the Company with adequate cash flow to meet its ongoing obligations.

Credit Facility

A sharp decline in oil prices in the latter quarter of 2014 and continued low prices during the first four months of 2015 has materially reduced our oil and gas cash flow. In response the company has taken steps to reduce G&A including layoffs, salary freezes, field operating expenses and plans no new capital drilling and completion in efforts to maximize available cash flow during these difficult times. These austerity measures aside the company is faced with liquidity and

debt challenges. As at December 31, 2014 has a working capital deficit of $71.4 million consisting of current assets of $6.91 million ($ .569 million cash) and current liabilities of $78.3 million. The company owes $50.5 million under its credit facility with Wells Fargo, $8.66 million to First Interstate Bank and trade payables and other of $18.9 million. With respect to the credit facility the US subsidiary was in breach of its current ratio covenant at December 31, 2014 and remains so. In addition the company is in breach of covenants around timely payments of trade payables and requirements that oil and gas assets remain free of liens. Liens have been filed totaling $7.2 million however agreements with certain lienholders have allowed for continued flow of production revenues to fund interest payments and critical ongoing operations and administration. The creditor is aware of these issues and has not taken any formal action to exercise rights and/or remedies under the credit agreement. Under the bank line of credit the company was in default due to non- payment of principal in interest in December and has not made payments for February and March 2015. At this time the bank has not taken any formal action to exercise its rights and/or remedies under the credit agreement. The company is involved in active discussions with its banks and trade creditors to negotiate a comprehensive solution to resolve our financial challenges. In addition the Company has longer term debts consisting of $10.7 million pursuant to outstanding promissory notes with an officer/director and two major shareholders and $2.3 million in convertible debenture a portion with an officer and director. These debts mature July 1, 2016 and are in good standing. The company is looking to include them in any comprehensive debt solution plan and is currently engaged in discussions to this end.

The company plans to continue negotiations and discussions with creditors to resolve our liquidity and debt challenges. In parallel the company is actively considering debt and equity financing solutions, assets sales and corporate transactions among other available alternatives in the best interest of the company.

For further information on such default, please see the audited financial statements of the Corporation, along with the notes thereto and management discussion and analysis as at and for the year ended December 31, 2014, which are filed on SEDAR.

Convertible Debentures

On May 28, 2012, the Company acquired from a related company owned by a director and officer in common, a compressor, plant and equipment for consideration of $2,660,000. The Company paid $283,000 and agreed to issue a $2,377,000 debenture convertible into common shares of the Company at a price of $2.50 per common share (the actual convertible debenture issued was $2,072,053, which was reduced by costs incurred of $304,947 on behalf of the related company prior to the transaction closing). During the year ended December 31, 2013 the original Convertible Debenture was cancelled and a new Convertible Debenture was signed to extend the maturity date to June 1, 2015. In the year ended December 31, 2014 an amendment to the debenture was issued extending the maturity date to July 1, 2016 all other terms remained unchanged. At December 31, 2014 the convertible debenture was $2,072,053 plus accrued interest of $227,756. Principal and interest payments are due at maturity. At December 31, 2014, if the convertible debenture had been converted the Company would have issued 919,924 additional common shares.

Promissory Notes

The Company entered into two unsecured promissory notes payable with major shareholders of the Company, each for $4,000,000 (total $8,000,000), bearing interest at 9% per annum and drawdown of the full principal balance. The principal was payable on or before May 30, 2015. During the year ended December 31, 2014, amendments to the promissory notes were executed extending the maturity to July 1, 2016. At December 31, 2014, the balance due on the promissory notes was $7,850,000 plus accrued interest of $1,632,144. Principal and interest payments are due at maturity.

On March 12, 2013, the Company entered into two unsecured promissory notes payable with major shareholders of the Company and a Company with a director and officer in common, for $250,000, bearing interest at 5% per annum. The principal was payable on or before March 12, 2015. During the year ended December 31, 2014, amendments to the promissory notes were executed extending the maturity to July 1, 2016. At December 31, 2014, the balance due on the promissory notes is $250,000 plus accrued interest of $22,964. Principal and interest payments are due at maturity.

On November 26, 2013, the Company signed three unsecured promissory notes payable with a major shareholder of the Company, for $460,949, $248,205, and $96,000, bearing interest at 9% per annum. The principal was payable on or before March 15, 2015, May 7, 2015 and June 6, 2015. During the year ended December 31, 2014, amendments to the

promissory notes were executed extending the maturity to July 1, 2016. At December 31, 2014, the balance due on the promissory notes is $805,154 plus accrued interest of $129,759. Principal and interest payments are due at maturity.

DIRECTORS AND OFFICERS

The following table sets forth (as at December 31, 2014) each of the directors and officers of Mountainview including name, age, province/state and country of residence, date first elected as a director of Mountainview, where applicable, and office held together with their principal occupations during the last five years. The directors of Mountainview shall hold office until the next annual meeting of Shareholders or until their respective successors have been duly elected or appointed.

Name, Municipality of Residence and Age	Position with Mountainview	Date First Elected or Appointed as Director	Principal Occupation for the Past Five Years
Patrick M. Montalban[(2)] Montana, USA Age: 58	President, Chief Executive Officer and Director	July 18, 2007	Director, President & Chief Executive Officer of Mountainview.
Bo Mikkelsen[(1)(2)(3)] Oklahoma, USA Age: 67	Director	June 17, 2003	President of Engine Technology Support, Inc., which applies patented emission control technology to industrial gas fuelled lean burn engines. Consulting oil and gas engineer for past 29 years covering North and South America and North Africa.
Carla Barringer[(1)] Montana, USA Age: 50	Corporate Secretary, Treasurer and Director	June 17, 2004	Director, Corporate Secretary and Treasurer of Mountainview.
Keith Macdonald[(1)(2)(3)] Alberta, Canada Age: 58	Director	December 31, 2010	President and a director of Bamako Investment Management Ltd., a private investment and financial consulting company.
Joseph Montalban Montana, USA Age: 29	Vice President, Business Development	January 8, 2013	Vice President, Business Development of Mountainview; Prior thereto, Manager of Operations with Mountainview Energy, Inc.
Justin Balkenbush Montana, USA Age: 42	Vice President, Operations	April 3, 2013	Vice President, Operations of Mountainview; Prior thereto, Senior Engineer with SM Energy, a public oil and gas exploration and production company.
Brent Osmond Alberta, Canada Age: 34	Vice President, Finance and Chief Financial Officer	December 20, 2013	Chief Financial Officer of Nytis Exploration Company Inc., a private oil and gas exploration and production company.

Notes:

(1) Member of the audit committee of the Board of Directors (the "**Audit Committee**").
(2) Member of the reserve, environmental, health and safety committee of the Board of Directors (the "**Reserve Committee**").
(3) Member of governance and compensation committee of the Board of Directors (the "**Governance and Compensation Committee**").
(4) The term of each director is until the next annual meeting of Shareholders or until their successors are elected, but not later than the date of the next annual meeting of Shareholders.

As at April 30, 2014, the directors and officers of Mountainview, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 8,158,060 Common Shares, representing approximately 9% of the issued and outstanding Common Shares. Mr. Montalban also beneficially owns, or controls or directs, directly or indirectly, 7,822,727 Class B common shares of Mountainview Energy (USA) Ltd., a wholly-owned subsidiary of the Corporation, which are convertible in accordance with their terms into Common Shares on a one for one basis and which, upon such conversion into Common Shares, would represent approximately 9% of the issued and outstanding Common Shares as at April 30, 2015.

Cease Trade Orders

To the knowledge of management, no director or executive officer of Mountainview is, as at the date of this Annual Information Form or has been, within the last ten years prior to the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Mountainview) that:

(a) was subject to a cease trade order, or similar order, or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days and was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or

(b) was subject to a cease trade order, or similar order, or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days and was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer, and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Bankruptcies

To the knowledge of management, no director or executive officer of Mountainview, or a shareholder holding a sufficient number of securities of Mountainview to affect materially the control of Mountainview:

(a) is as at the date of this Annual Information Form, or has been within the last ten years prior to the date of this Annual Information Form, a director or executive officer of any company (including Mountainview) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

(b) has, within the last ten years prior to the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of director, executive officer or shareholder.

Penalties and Sanctions

To the knowledge of management, no director or executive officer of Mountainview, or a shareholder holding a sufficient number of securities of Mountainview to affect materially the control of Mountainview, has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Mountainview will be subject to in connection with the operations of Mountainview. In particular, certain of the directors and officers of Mountainview are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with Mountainview or with entities which may, from time to time, provide financing to, or make equity investments in, its competitors. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with Mountainview are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the material contract.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate

The mandate of the Audit Committee is attached hereto as Schedule "D".

Composition of the Audit Committee

The Audit Committee is comprised of Keith Macdonald, Bo Mikkelsen and Carla Barringer. Messrs. Macdonald and Mikkelsen are "independent" within the meaning of Section 1.4 of NI 52-110 and "financially literate" within the meaning of Section 1.6 of NI 52-110. Ms. Barringer, Corporate Secretary and Treasurer of the Corporation, is not "independent" within the meaning of Section 1.4 of NI 52-110 as she is employed by the Corporation. Ms. Barringer is "financially literate" within the meaning of Section 1.6 of NI 52-110.

Relevant Education and Experience

Keith Macdonald

Mr. Macdonald received his Bachelor of Commerce degree from the University of Calgary in 1978 and earned his Chartered Accountant Designation in 1980. He is currently a member of the Institute of Chartered Accountants of Alberta and the Canadian Institute of Chartered Accountants.

Mr. Macdonald is President of Bamako Investment Management Ltd., a private holding and financial consulting company. Mr. Macdonald is also a director of the following companies:

- Bellatrix Exploration Ltd., which is listed on the Toronto Stock Exchange (the "**TSX**");
- Madalena Energy Inc., which is listed on the TSXV; and
- Surge Energy Inc., which is listed on the TSX.

Mr. Macdonald serves as chair and/or member of the audit committees with all these companies.

Bo Mikkelsen

Mr. Mikkelsen has a Bachelor of Engineering (Mechanical) degree and a Master of Engineering (Mechanical) degree from the University of Manitoba granted in 1969 and 1971, respectively. Prior to working with stationary engine emissions controls, Mr. Mikkelsen operated a consulting engineering firm, Dan-Bo Energy, established in 1976, which specialized in design and construction of natural gas processing facilities.

Mr. Mikkelsen is the founder and President of Engine Technology Support, Inc. established in 1993. This company patented emission control technology to industrial, fuel lean burn engines. He has been President of Emissions Plus, Inc., since 1988, a company founded to apply the PSC System of emission control to industrial, gas fuelled rich burn engines.

Carla Barringer

Ms. Barringer has worked in the oil and gas industry since 1991, beginning with MSR Exploration Ltd., an Alberta public oil & gas exploration company listed for trading on the American Stock Exchange. She has been with Mountainview since May 2001 and currently serves as a director and is the Corporate Secretary and Treasurer. Ms. Barringer is also the Corporate Secretary of Altamont Oil & Gas, Inc. and Montalban Oil & Gas Operations, Inc. She is responsible for maintaining a functioning corporate office for these companies; covering all aspects from corporate correspondence and accounting to overseeing all filings with the respective regulatory bodies

Pre-Approval Policies and Procedures

The Audit Committee has not adopted any specific policies or procedures for the engagement of non-audit services.

External Auditor Service Fees

The following table sets forth the aggregate fees billed to the Corporation by PricewaterhouseCoopers LLP, Chartered Accountants, for services rendered in the fiscal years ended December 31, 2014 and 2013.

	2014	2013
Audit fees[(1)]	$142,500	$125,000
Audit-related fees[(2)]	$100,000	$14,500
Tax fees[(3)]	Nil	Nil
All other fees[(4)]	Nil	Nil
Total	$242,500	$139,500

Notes:

(1) Audit fees include fees billed regarding the annual audit and the review of interim financial statements.
(2) Audit-related fees include amounts billed for assurance related services that are reasonably related to the performance of the audit or the review of interim financial statements that are not reported under "Audit fees".
(3) Fees in connection with preparation of Canadian and U.S. tax returns.
(4) Other fees charged by the auditors, including other non-audit products and services.

Exemption

The Corporation is relying upon the exemption in section 6.1 of NI 52-110 as the Corporation, as a venture issuer within the meaning ascribed thereto in NI 52-110, is exempt from the requirements of Part 3 (*Composition of the Audit Committee*) and has, since the commencement of the Corporation's most recently completed financial year, relied upon the exemption in section 6.1 of NI 52-110 with respect to Part 5 (*Reporting Obligations*) of NI 52-110.

INDUSTRY CONDITIONS

United States Oil and Natural Gas Industry

Overview

The oil and gas industry in the United States is very well-established. Since the 1860's, oil has been produced in economic quantities in a number of discrete sedimentary basins in the lower 48 states and Alaska. Accompanying this production has been the development of supportive infrastructure including pipelines, gas processing facilities and a drilling and service sector as well as a wide range of professional services.

The demand for low cost, domestic sources of hydrocarbons remains strong. U.S. domestic policy has historically supported the development and exploitation of oil and gas reserves to assure access to domestic supplies of hydrocarbons. Many state and municipal governments are also supportive and recognize the monetary contribution that the industry makes to their state and municipal budgets. In Montana and North Dakota, the jurisdictions where the Corporation's oil and gas interests are located, oil has been produced since 1920 and 1951, respectively.

Background

This section provides a brief overview of the legal structure of the parts of the U.S. oil and natural gas exploration and production industry in which the Corporation operates.

In the United States, ownership of land carries with it ownership of or the exclusive right to materially benefit from the extraction of substances from under the surface, including oil, natural gas and other minerals. A landowner may convey an estate in the oil and natural gas rights separate and apart from the ownership of the surface rights. When the oil and natural gas interest is severed from the surface interest, two distinct estates or interests are created — the mineral estate and the surface estate.

The owner of the mineral estate has many interests which are capable of being conveyed alone or in various combinations, including the right to convey a working interest to an oil and natural gas exploration and production company to explore for and produce oil and natural gas from the mineral estate. Such a working interest is typically conveyed by the owner or owners of the mineral estate to the working interest owner pursuant to a lease agreement. The owner of the mineral estate typically retains a royalty interest, which is the right to receive a specified percentage of the production of any oil and natural gas recovered from the mineral estate prior to deduction of any costs or expenses.

The rights of exploration, drilling and production conveyed by a typical lease agreement customarily require that production of oil and natural gas in paying quantities be established within a specified period of time, typically two to five years. Absent an ability to extend the primary term of the lease, the lease terminates if such production is not established within the specified time period. Once such production is established during the primary term, the lease agreement would generally continue in effect (either in whole or in part as to the proration units located around producing wells) so long as production in paying quantities continues. However, the interest of the lessee under an oil and gas lease is capable of being abandoned by the lessee and may also be subject to forfeiture for failure on the part of the lessee to comply with express covenants and implied obligations, including, for example, the duty to reasonably develop the premises, the duty to protect the leasehold against drainage and the duty to manage and administer the lease.

Operations

Acquisitions

For certain petroleum properties where the Corporation does not own a 100% working interest, the Corporation has been appointed as the operator in the petroleum properties pursuant to the terms of joint operating agreements. This is the case for the Corporation's properties in the Williston Basin and for some of its properties in Montana. Joint operating agreements govern the operation of the petroleum properties as between the Corporation and other working interest owners in those properties. Pursuant to such agreements, the Corporation, in its capacity as operator, conducts the day-to-day operations for these properties. As the operator and the majority interest owner in such properties, the Corporation has the ability to manage the capital spending as contemplated by the applicable agreements, in accordance with the rights and powers typically afforded (in both Canada and the U.S.) to majority interest owners as a standard term of such agreements.

Marketing

The Corporation sells 100% of its crude oil production from Divide County, North Dakota to Sunoco Partners Marketing & Terminals L.P. ("**Sunoco**") pursuant to contracts based and adjusted for transportation and marketing. The Corporation's crude oil production is sold to Sunoco on a month-to-month agreement until terminated by either party.

The Corporation sells 100% of its crude oil production from Glacier, Pondera, and Teton Counties, Montana ("**Legacy Oil Properties**") to CHS, Inc ("**CHS**") pursuant to contracts based on the West Texas Intermediate pricing index, and

adjusted for transportation and marketing. The Corporation's contracts with CHS on its Legacy Oil Properties are on a month-to-month agreement until terminated by either party.

The Corporation sells 100% of its natural gas production from Divide County, North Dakota to USG Midstream Bakken 1, LLC (**"USG"**) pursuant to contracts based on the market value of Natural Gas Liquids. The value of the gas sold by the Corporation is determined by the liquid content of the gas processed by USG. The agreement is in place until October 1, 2023.

The Corporation sells its natural gas in the Williams and Lake Frances Fields in Pondera County, Montana to a single buyer pursuant to various contracts based on location. Approximately 95% of 2014 gas volumes were sold to Energy West, Inc. ("**Energy West**"). The Corporation's contracts with Energy West are binding until October 2014, after which the contracts may be renewed annually. No other purchaser of gas volumes in 2013 accounted for more than 5% of the Corporation's total gas volumes. The Corporation sells approximately 5% of 2013 gas volumes to the East Butte Gathering Systems, LLC from its non-operated interests in the Snoose Coulee Field in Liberty County, Montana.

Title to Properties

It is customary in the U.S. oil and natural gas industry to conduct a preliminary review of title to both producing and non-producing properties. Prior to the commencement of drilling operations on those properties, a title examination typically is performed and curative work is undertaken with respect to significant defects. Management follows customary U.S. industry due diligence practices in connection with its acquisitions, including performing title reviews on producing properties, undeveloped properties that are assigned significant value and the more significant leases prior to completing an acquisition and, depending on the materiality of the properties, management may obtain title opinions or reports or review previously obtained title opinions or reports. Depending on the nature of each acquisition, to the extent title opinions or other investigations reflect material title defects, one of either the purchaser or the seller would be responsible for the costs and for curing any title defects. As discussed above, a title examination on other properties and leaseholds would typically be performed prior to the commencement of drilling operations thereon and any curative work would be performed. The Corporation's oil and natural gas properties will be subject to customary royalty and other interests, liens for current taxes and other customary burdens. See "*Risk Factors*".

Competition

The U.S. petroleum industry is highly competitive in all phases. The Corporation will encounter competition from other petroleum companies in all areas of operations, including the acquisition of leasing options on petroleum properties and the exploration and development of those properties. The Corporation's competitors will include numerous independent petroleum companies, individuals, and drilling and income programs. Many of the Corporation's competitors are large, well established companies that have substantially larger operating staffs and greater capital resources than the Corporation. Such competitors may be able to pay more for lease options on petroleum properties and to define, evaluate, bid for and purchase a greater number of properties and locations than the financial or human resources of the Corporation will permit. The Corporation's ability to acquire additional properties and to discover reserves in the future will depend upon its ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment.

Regulation of the Petroleum Industry

Operations will be substantially affected by U.S. federal, state and local laws and regulations. In particular, petroleum production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which the Corporation owns or operates properties for petroleum production have statutory provisions regulating the exploration for and production of petroleum, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of petroleum wells, and regulations that generally prohibit the venting or flaring of natural gas and that impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties, and the regulatory burden on the industry in the U.S. increases the cost of doing business and affects profitability. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by U.S. congress ("**Congress**"), the states, the Federal Energy Regulatory Commission, ("**FERC**") and the courts. The Corporation cannot predict when or whether any such proposals may become effective, nor can they estimate the costs of complying therewith.

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could re-enact price controls in the future.

Sales of crude oil will be affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the *Interstate Commerce Act*. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC issued Order No. 561, which established an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index ceiling slightly, effective July 2001. Following the FERC's five-year review of the indexing methodology, the FERC issued an order in 2006 increasing the index ceiling. In 2010, FERC issued a final order concluding its third five-year review of the oil-pricing index. In this 2010 order, FERC again raised the index ceiling, establishing an index level of Producer Price Index for Finished Goods, plus 2.65% adjustment for the five-year period commencing July 1, 2011.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this common carrier standard, pipelines must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by pro-rationing provisions published by the pipeline. Accordingly, Management believes that access to oil pipeline transportation services generally will be available to the Corporation to the same extent as to similarly situated competitors.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the *Natural Gas Act of 1938* ("**NGA**"), the *Natural Gas Policy Act of 1978* (the "**NGPA**"), and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could re-enact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the *Natural Gas Wellhead Decontrol Act* which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. The jurisdictions in which the Corporation's production is located and in which management anticipates operating have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas wells that a corporation can produce from and to limit the number of wells or the locations at which a corporation can drill, although a corporation can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each jurisdiction generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids.

The failure to comply with these rules and regulations can result in substantial penalties. Competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect the Corporation's operations.

Other Federal Laws and Regulations Affecting the Industry

The *Energy Policy Act of 2005* (the "**EPAct 2005**") is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the U.S. energy industry. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behaviour to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. EPAct 2005 provides the FERC with the power to assess civil penalties of up to $US 1,000,000 per day for violations of the NGA and increases the FERC's civil penalty authority under the NGPA from $US 5,000 per violation per day to $US 1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale and/or transportation of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, (1) to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or to omit to state a material fact necessary in order to make the statements made, in the light of the circumstances under which they were made, not misleading; or (3) to engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as NGPA Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority. Should management fail to comply with all applicable FERC administered statutes, rules, regulations, and orders, the Corporation could be subject to substantial penalties and fines.

FERC Market Transparency Rules

On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Under Order No. 704, wholesale buyers and sellers of more than 2.5 MMbtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, on May 1 of each year beginning in 2009, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to, the formation of price indices. In order to provide respondents time to implement new regulations related to Order No. 704, the FERC extended the deadline for calendar year 2009 until October 1, 2010. The report for calendar year 2010 and subsequent years remains May 1 of the following calendar year. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting.

FERC also issued Order Nos. 720 and 720-A. Order No. 720 required major non-interstate pipelines to post scheduled flow information, as well as information for receipt and delivery points with design capacity greater than 15,000 MMbtu/day. Order No. 720 also required interstate pipelines to post information regarding no-notice service (that is, firm transportation service by which firm shippers may receive delivery up to their firm entitlements on a daily basis without penalty). Order No. 720-A broadly affirmed Order No. 720. However, in 2011, the U.S. Circuit Court of Appeals for the 5th Circuit vacated Order Nos. 720 and 720-A insofar as the orders imposed reporting requirements on non-interstate pipelines.

In November 2012, FERC issued a Notice of Inquiry seeking comments on what changes, if any, should be made to its natural gas market transparency. Specifically, FERC sought comments on whether quarterly reporting of every gas transaction within its jurisdiction involving physical delivery for the next day or next month would increase transparency. FERC received 34 comments in response to the Notice of Inquiry. Many of the commenters argued that the proposal to collect additional information in quarterly reports would not enhance market transparency. Accordingly,

FERC collected data from certain natural gas marketers pursuant to its authority under section 375.311 of the regulations to evaluate the commenters' assertions. FERC has taken no further action on the matter since July of 2013.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. Management cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. Management does not believe that the Corporation would be affected by any such action materially differently than similarly situated competitors.

Environmental, Health and Safety Regulation

Exploration, development and production operations are subject to various federal, state and local laws and regulations governing health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment in connection with oil and gas drilling and production; require the installation and operation of pollution controls and the monitoring and reporting of pollutants released into the environment; restrict the way the Corporation handles or disposes of wastes; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions caused by operations or attributable to former operations; and impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all operations in affected areas.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly waste handling, disposal, cleanup and remediation requirements for the oil and gas industry could have a significant impact on operating costs.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal, or remediation requirements could have a material adverse effect on our operations and financial position. Of particular note, the U.S. Environmental Protection Agency ("**EPA**") has recently made the enforcement of environmental laws in the oil and gas exploration and production sector a formal enforcement priority. Increased compliance costs may not be able to be passed on to purchasers or customers. Moreover, accidental releases or spills may occur in the course of operations, and the Corporation cannot assure securityholders that it will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which the Corporation's business operations are subject and for which compliance may have a material adverse impact on capital expenditures, results of operations or financial position.

Hazardous Substances and Waste

The *Comprehensive Environmental Response, Compensation, and Liability Act*, as amended, (the "**CERCLA**"), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where a release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these "responsible persons" may be subject to joint and several, strict liability for the costs of cleaning up hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible persons the costs they incur. It is not uncommon for neighbouring landowners and other third parties to file claims for personal injury and property

damage allegedly caused by the release of hazardous substances or other pollutants into the environment. Operations will generate materials that may be regulated as hazardous substances.

Management anticipates operations will also generate solid and hazardous wastes that are subject to the requirements of the *Resource Conservation and Recovery Act*, as amended, (the "**RCRA**"), and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Management anticipates that operations will generate petroleum hydrocarbon wastes and ordinary industrial wastes that may be regulated as hazardous wastes.

The Corporation owns and leases and, in connection with future acquisitions, will acquire, properties that have been used for numerous years to explore and produce oil and natural gas. Hydrocarbons and wastes may have been disposed of, or released on or under, the properties owned or leased by the Corporation or on or under other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties may have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes was not under the Corporation's control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, the Corporation could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial operations to prevent future contamination.

Air Emissions

The *Clean Air Act*, as amended, and comparable state laws and regulations restrict the emission of air pollutants from many sources and also impose various monitoring and reporting requirements. These laws and regulations may require the Corporation to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits, including air emission allowances and credits, has the potential to delay and increase the cost of the development of oil and natural gas projects. In addition, the EPA and state regulators have underway a number of regulatory changes (including the EPA's new compressor engine emissions standards, potential revisions to the New Source Performance Standards for the oil and natural gas sector, and the potential aggregation of exploration and production-related emissions sources to make what have historically been multiple "minor" sources into larger "major" sources that are then subject to more stringent regulation). Each of these may significantly increase the regulatory burdens and costs of U.S. oil and gas exploration.

Climate Change

In response to certain scientific studies suggesting that emissions of certain gases, commonly referred to as "greenhouse gases" ("**GHG**") and including carbon dioxide and methane, are contributing to the warming of the Earth's atmosphere and other climatic changes, in 2009 and 2010 Congress considered legislation to reduce such emissions. On June 26, 2009, the U.S. House of Representatives passed the *American Clean Energy and Security Act of 2009* (the "**ACESA**"), which would have established an economy-wide cap-and-trade program to reduce U.S. emissions of GHG including carbon dioxide and methane that may contribute to warming of the Earth's atmosphere and other climatic changes. ACESA would have required a 17% reduction in GHG emissions from 2005 levels by 2020 and just over an 80% reduction of such emissions by 2050. Under this legislation, the EPA would have issued a capped and steadily declining number of tradable emissions allowances to major sources of GHG emissions so that such sources could continue to emit GHG into the atmosphere. These allowances would be expected to escalate significantly in cost over time. The U.S. Senate considered pursuing its own legislation for restricting domestic GHG emissions and President Obama indicated his support of legislation to reduce GHG emissions through an emission allowance system. However, in July 2010, Senate Majority Leader Harry Reid said the Senate would not take up the ACESA, and the 111th Congress ended in December 2010 without passing the ACESA. The ACESA would now need to be passed by the Senate and re-passed by the House to become law, and the current prospects of that are extremely unlikely given Republican control of the House. Any future federal laws or implementing regulations that may be adopted to address GHG emissions could require the Corporation to incur increased operating costs and could adversely affect demand for the oil and natural gas produced.

In the face of congressional inaction, the Obama Administration has announced its intention to address climate change through executive action such as rulemaking. The U.S. Supreme Court held in 2007 that the EPA has the authority and the obligation under the *Clean Air Act* to address climate change through the regulation of GHG if the EPA finds that

such emissions present the threat of endangerment to public health or welfare. Though that case focused on motor vehicle emissions, the EPA interprets it to apply to stationary source emissions as well. Following that decision, on December 15, 2009, the EPA published its finding that emissions of GHGs presented an endangerment to human health and the environment. The endangerment finding allowed the EPA to proceed with the adoption and implementation of regulations to restrict emissions of GHGs under existing provisions of the federal *Clean Air Act*. Consequently, the EPA proposed two sets of regulations that would require a reduction in emissions of GHGs from motor vehicles and could trigger permit review for GHG emissions from certain stationary sources. EPA also published a final rule on October 30, 2009, requiring the reporting of GHG emissions from specified large GHG emission sources in the U.S. beginning in 2011 for emissions occurring in 2010. EPA subsequently expanded the reporting rule to include GHG emissions from owners and operators of onshore oil and natural gas production. Several of EPA's recently finalized rules regulating emissions of GHGs have been challenged in a case currently pending before the U.S. Supreme Court, Utility Air Regulatory Group v. EPA, in which a decision is expected in the first half of 2014. The decision in Utility Air Regulatory Group action could impact the costs incurred by the Corporation and the demand for the oil and natural gas it produces. The EPA is also in the process of developing the first sector-wide standards for emissions of GHGs under the *Clear Air Act's* new source performance standard provisions. The first standards will cover large, fossil fuel-fired power plants. Subsequent standards will cover existing power plants. Eventually, EPA may be required to develop standards for a broad range of industrial sectors, which could include the oil and gas production sector. EPA is also in the initial stages of studying emissions of methane from compressors, completions and production of hydraulically fractured oil wells, leaks, liquids unloading, and pneumatic devices. These studies could lead to regulations specifically targeted to oil and gas production and could further impact the costs incurred by the Corporation and the demand for the oil and natural gas it produces.

In addition to federal activity, more than one-third of the states have begun taking actions to control and/or reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Although most of the state-level initiatives have to date focused on large sources of GHG emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations or allowance purchase requirements in the future. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on the Corporation's business, financial condition and results of operations. In Montana and North Dakota, the state agencies responsible for regulating air emissions are the Montana Board of Oil & Gas ("**MBOG**") and the North Dakota Industrial Commission, Oil and Gas Division ("**NDIC**"), respectively.

Water Discharges

The *Federal Water Pollution Control Act*, as amended, or the *Clean Water Act*, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into navigable waters. Pursuant to the *Clean Water Act* and analogous state laws, permits must be obtained to discharge pollutants into, and in certain instances withdraw water from, state waters or U.S. waters. Any such discharge of pollutants into regulated waters or withdrawal of water must be performed in accordance with the terms of the permit issued by the EPA or the analogous state agency. The EPA has recently proposed a rule that could significantly increase the number and types of waters that would be subject to federal, as opposed to state, permitting requirements. That rule is expected to be finalized within a year, but is likely to be heavily litigated. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the *Clean Water Act* and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. In Montana and North Dakota the MBOG and NDIC, respectively, are the state environmental agencies responsible for regulating water quality and discharges of pollutants into water.

The *Oil Pollution Act of 1990*, as amended, (the "**OPA**"), which amends the *Clean Water Act*, establishes strict liability for owners and operators of facilities that are the site of a release of oil into U.S. waters. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect U.S. waters.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list, nor should be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

Going Concern

The Company has experienced losses in the years ended December 31, 2014 and December 31, 2013. At December 31, 2014 and December 31, 2013, the Company had a deficit of $71,847,790 and $17,500,630 respectively, and a working capital deficit of $71,403,601 and $5,236,932 respectively. Continuing operations, as intended, are dependent on management's ability to raise required funding through future equity issuances, credit facilities, asset sales or a combination thereof, which is not assured, especially in current volatile and uncertain financial and commodity price environment. The sharp decline in commodity prices during the latter half of 2014 materially reduced the revenues that were generated from the sale of oil and gas production volumes during that period which, in turn, negatively affected the Company's working capital balance and the ability of the Company to secure additional financing. There is potential for future commodity prices to remain at current price levels for an extended period of time and should the current commodity price environment continue for a prolonged period of time, the Company will need to negotiate with its creditors to improve payment terms and/or pursue some form of asset sale, debt restricting, equity financing or other capital raising effort in order to fund its operations and to service its existing debt during the next twelve months. In addition, liens have been filed on the Company's assets in the months subsequent to December 31, 2014. While these liens do not presently impact cash flow, the vendors who have filed the liens may, in fact, restrict cash flow from the wells under lien, further reducing the cash flow available to the Company. Any sale of assets with outstanding liens would require that the lien be cleared before title can be transferred. This condition also limits the proceeds of any potential asset sale. The Company is also in breach of debt covenants under the agreements governing the line of credit and credit facility (See Note 12 of the Company's audited finaicial statements). The line of credit and credit facility mature and are due and payable in 2015. Management of the Company is actively pursuing strategies to improve its working capital position and/or to reduce its future debt service costs, through the aforementioned means. The Company believes that these actions will mitigate the adverse conditions that the Company is facing; however, there is no certainty that these and other strategies will be successful or permit the Company to continue as a going concern.

These material uncertainties cast significant doubt on the Company's ability to continue as a going concern. If the Company is unable to restructure its debt in an acceptable manner, obtain additional adequate debt or equity financing or achieve adequate proceeds from the sale of assets, the Company will pursue all other legal avenues available to it with a view to improving the Company's financial situation in the best interests of the Company. These audited consolidated financial statements do not include any adjustments to the recoverability and classification of recorded asset amounts and classification of liabilities and related expenses that might be necessary, should the Company be unable to continue as a going concern. Should the going concern assumption not be appropriate and the Company is not able to realize its assets and settle its liabilities, these statements would require adjustments to the amounts and classifications of assets and liabilities and these adjustments could be material.

Additional Funding Requirements

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

Because of the global economic volatility, the Corporation may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable, or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future

development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Substantial Capital Requirements

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

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

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Non-compliance with the covenants under the Credit Facility could adversely affect the financial condition of the Corporation.

The Corporation is required to comply with covenants under the Credit Facility. In the event that it does not comply with covenants under the Credit Facility, access to capital could be restricted or repayment could be required on an accelerated basis by the Lender. The Lender has security over substantially all of the assets of the Corporation's 12 Gage project. If the Corporation becomes unable to pay its debt service charges or otherwise commits an event of default such as breach of its financial covenants, the Lender may foreclose on or sell the Corporation's working interests in its properties. Although management believes the Credit Facility will be sufficient to meet the Corporation's financial needs for the near term, there can be no assurance that the amount will be adequate for the Corporation's future financial obligations including the Corporation's future capital expenditure programs, or that additional funding will be obtained.

The Corporation's level of indebtedness may reduce financial flexibility.

The Corporation may incur significant indebtedness in the future, including under the Credit Facility, in order to acquire new properties or develop existing properties. Management intends to manage in a financially conservative manner. In order to facilitate the management of this debt, the Corporation prepares annual capital expenditure budgets, which are updated, as necessary, depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. The annual and updated budgets are approved by the Board of Directors. In the event that debt levels exceed the limits stated above, operations could be affected in several ways, including the following:

- a significant portion of cash flow could be used to service indebtedness;
- a high level of debt would increase vulnerability to general adverse economic and industry conditions;
- the covenants contained in the Credit Facility will limit the Corporation's ability to borrow additional funds, dispose of assets, pay distributions and make certain investments;
- a high level of debt may place the Corporation at a competitive disadvantage compared to competitors that are less leveraged and therefore, may be able to take advantage of opportunities that the Corporation's indebtedness would prevent it from pursuing;
- the Corporation's debt covenants may also affect flexibility in planning for, and reacting to, changes in the economy and in the industry;

- a high level of debt may make it more likely that a reduction in the Corporation's borrowing base following a periodic redetermination could require the Corporation to repay a portion of then-outstanding bank borrowings; and
- a high level of debt may impair the ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that the Corporation may default on its debt obligations. The Corporation's ability to meet its debt obligations and to reduce its level of indebtedness depends on future performance. General economic conditions, oil, natural gas liquids and natural gas prices, and financial, business and other factors affect operations and future performance. Many of these factors are beyond the Corporation's control. The Corporation may not be able to generate sufficient cash flow to pay the interest on debt and future working capital, borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect the ability to raise cash through an offering of capital stock or a refinancing of debt include financial market conditions, the value of assets and performance at the time the Corporation needs capital.

Many of the risk factors outlined above are likely to occur only in the event that the Corporation incurs high levels of debt or if the Corporation's producing properties suffer a substantial impairment that has a material impact on cash flow from operations or if a substantial decline in the price of oil or natural gas were to occur.

Credit Facility Arrangements

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

The Corporation's Lender uses the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facility which could result in the requirement to repay a portion, or all, of the Credit Facility.

Market Price of Common Shares

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

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new

reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and on its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

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

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, and spills or other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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

Issuance of Debt

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

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader U.S. and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and

other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by OPEC and the ongoing global credit and liquidity concerns. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Project Risks

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the supply of, and demand for, oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that it produces effectively.

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. Deliverability uncertainties related to the distance the Corporation's reserves are to pipelines, processing and storage facilities, operational problems affecting pipelines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

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

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

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

Dilution

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering, processing and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limits the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and financial condition, results of operations and cash flows.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease

operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Corporation's ability to process its production and to deliver the same for sale.

Competition

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

Cost of New Technologies

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

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil and other liquid hydrocarbons. The Corporation cannot predict the impact of a 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.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (exploration, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the industry could reduce the demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require licenses from various governmental authorities and 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 it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. Specifically, hydraulic fracturing is used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's costs of compliance and doing

business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state, provincial and local laws and regulations. Environmental legislation and regulation 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 and regulations also require that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

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

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit GHGs which may require the Corporation to comply with GHG emissions legislation in the jurisdictions in which it has operations. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and as a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction GHG emissions from 2005 levels by 2020. In the United States, the Obama Administration has announced a similar goal, with a further goal of reducing GHG emissions by 70% from 2005 levels by 2050. These GHG emission reduction targets are not binding, however. Although it is not the case today, some of the Corporation's significant facilities may ultimately be subject to future regional, state, provincial and/or federal climate change regulations to manage GHG emissions. These regulations, unlike the current reduction targets, are likely to be binding and enforceable. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of GHGs and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition.

Variations in Foreign Exchange Rates and Interest Rates

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

Hedging

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

- production falls short of the hedged volumes;

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

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities are 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.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim. The actual interest of the Corporation in properties may, therefore, vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties the Corporation controls that, if successful or made into law, could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this Annual Information Form are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as:

(i) historical production from the properties;

(ii) production rates;

(iii) ultimate reserve recovery;

(iv) timing and amount of capital expenditures;

(v) marketability of oil and natural gas;

(vi) royalty rates; and

(vii) the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

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

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods

are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices may result in variations in the estimated reserves. Such variations could be material.

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

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

Insurance

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

Geopolitical Risks

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

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

Management of Growth

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

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working

interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Canadian and United States Reserves and Production Reporting Practices

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by U.S. companies.

The primary differences between the Canadian and U.S. reporting requirements include the following: (i) the Canadian standards require disclosure of proved and probable reserves, while the U.S. standards require disclosure of only proved reserves; (ii) the Canadian standards permit the disclosure of oil and gas resources, while the U.S. standards prohibit such disclosure; (iii) the Canadian standards require the use of forecast prices in the estimation of reserves, while the U.S. standards require the use of 12-month average prices which are held constant; (iv) the Canadian standards require disclosure of reserves on a gross (before royalties) and net (after royalties) basis, while the U.S standards require disclosure on a net (after royalties) basis; (v) the Canadian standards require disclosure of production on a gross (before royalties) basis, while the U.S. standards require disclosure on a net (after royalties) basis; and (vi) the Canadian standards require that reserves and other data be reported on a more granular product type basis than required by the U.S. standards.

Dividends

The Corporation has not paid any dividends on its outstanding Common Shares. Payment of dividends in the future will be subject to the terms and conditions of the Credit Facility and will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations, as the board of directors of the Corporation considers relevant.

Litigation

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

Breach of Confidentiality

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

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and the *U.S. Internal Revenue Code of 1986*, as amended, and all other applicable provincial and state tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. In the U.S., changes in the

federal income tax laws proposed by the Obama Administration would have an adverse impact on oil and gas companies. At this time, it is unclear whether such proposed changes will become law. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates income for tax purposes or could change administrative practices to the Corporation's detriment.

Seasonality

The level of activity in the oil and natural gas industry in the jurisdictions in which the Corporation operates 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 as the demand for natural gas rises during cold winter months and hot summer months.

Third Party Credit Risk

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

Conflicts of Interest

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

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of management of the Corporation.

Expansion into New Activities

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

New U.S. regulation of derivatives trading could reduce hedging opportunities and negatively affect the Corporation's results.

New U.S. regulation of derivatives trading could reduce hedging opportunities and negatively affect the Corporation's results. In 2010, the U.S. Congress enacted the *Dodd Frank Wall Street Reform and Consumer Protection Act* (the "**Dodd Frank Act**"), which contains measures aimed at increasing the transparency and stability of the over the counter (OTC) derivative markets and preventing excessive speculation. Pursuant to the Dodd Frank Act, the U.S. Commodity Futures Trading Commission (the "**CFTC**") enacted regulations that impose, among other things, reporting requirements and leverage limitations on certain types of financial transactions. Most energy transactions are exempt from these regulations and requirements. However, the CFTC continues to issue new and revised regulations and the precise application of either the Dodd Frank Act or the CFTC's regulations is yet to be determined. In the future, the Corporation may use the OTC market for its oil and natural gas derivative contracts. However, the Dodd Frank Act or the CFTC's regulations could reduce liquidity in the energy futures markets. Such changes could materially reduce hedging opportunities and negatively affect revenues and cash flow during periods of low commodity prices.

Regulation of environmental matters related to climate change could have a negative impact on the Corporation.

Federal and state governments are considering enacting new legislation and promulgating new regulations governing or restricting the emission of GHGs from certain stationary sources common in the Corporation's industry. The EPA has already made findings and issued proposed regulations that could lead to the imposition of restrictions on GHG emissions from certain stationary sources and that could require the Corporation to establish and report an inventory of GHG emissions. EPA is also currently studying whether methane emissions associated with oil and natural gas production separately require regulation to address climate change impacts. In addition, Congress has previously considered bills that would establish an economy-wide cap-and-trade program to reduce U.S. emissions of GHGs, including carbon dioxide and methane. Such legislation is not likely to be enacted in the near term, however, that may change at some point in the future. Such a program, if enacted, could require phased reductions in GHG emissions over several or many years as could the issuance of a declining number of tradable allowances to sources that emit GHGs into the atmosphere. Legislative and regulatory proposals for restricting GHG emissions or otherwise addressing climate change could require the Corporation to incur additional operating costs and could adversely affect demand for the oil and natural gas that the Corporation sells. At the state level, the Corporation is aware of changes in air quality standards that are regulated in Montana and North Dakota by the MBOG and the NDIC, respectively, and is implementing changes at its facilities to meet or exceed these new standards. The potential increase in operating costs could include new or increased costs to obtain permits, operate and maintain equipment and facilities, install new emission controls on equipment and facilities, acquire allowances to authorize GHG emissions, pay taxes related to GHG emissions and administer and manage a GHG emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for oil and natural gas.

Increased regulation of hydraulic fracturing and oil and gas development could result in reductions or delays in production, which could adversely impact the Corporation's revenues.

A number of federal agencies, including the EPA and the U.S. Department of Energy, are analyzing, or have been requested to review, a variety of environmental issues associated with oil and gas development, including hydraulic fracturing. In addition, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the *Safe Drinking Water Act's* Underground Injection Control Program and has begun the process of drafting guidance documents related to this assertion of regulatory authority. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, industry groups have filed suit challenging the EPA's recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with the initial progress report released December 2012 and a final draft report is expected to be released for public comment and peer review in 2014. In the interim, however, the EPA has utilized its existing *Safe Drinking Water Act's* enforcement authority to order actions and potentially to pursue penalties against some oil and natural gas producers where EPA believes their activities may have impacted groundwater. Also, for the second consecutive session, legislation has been introduced before Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities by the end of 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing, with the U.S. Department of Interior currently developing a rule to require oil and natural gas producers to publicly disclose their

hydraulic fracturing chemicals in connection with their drilling of wells on federal lands. These studies or reviews, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal *Safe Drinking Water Act* or other regulatory mechanisms. In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. In addition, some states and municipalities have adopted, and other states and municipalities are considering adopting, moratoriums and/or regulations that could impose more stringent disclosure and/or well construction requirements on hydraulic fracturing operations or ban such operations altogether. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for the operators to perform fracturing to stimulate production from tight formations. Restrictions on hydraulic fracturing could also reduce the amount of oil, natural gas and natural gas liquids that are ultimately produced in commercial quantities from the Corporation's properties. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, the Corporation's business and operations and the properties in which the Corporation has an interest could be subject to additional permitting requirements, and also to attendant permitting delays, increased operating and compliance costs and process prohibitions.

On April 17, 2012, the EPA approved final regulations under the *Clean Air Act* that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("**VOCs**") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flow-back emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. Compliance with these requirements could require a number of modifications to operations, including the installation of new equipment, and could significantly increase the Corporation's costs of development and production, although the Corporation does not expect these requirements to be any more burdensome to the Corporation than to other similarly situated companies involved in oil and natural gas exploration and production operations.

At the same time, certain environmental groups have suggested that additional laws may be needed to more closely and uniformly regulate the hydraulic fracturing process and legislation has been proposed by some members of Congress to provide for such regulation. The Corporation cannot predict whether any such legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, that could lead to delays, increased operating costs and process prohibitions that could reduce the volumes of natural gas that move through the Corporation's gathering systems which would materially adversely affect the Corporation's revenues and results of operations.

The Corporation may incur losses as a result of title defects in the properties in which the Corporation invests.

Industry practice in the U.S. for acquiring oil and gas leases or interests does not typically involve retaining lawyers to examine the title to the mineral interest and instead relies upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. Prior to the drilling of an oil or gas well, however, it is the normal practice in the industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Failure to cure any title defects may adversely impact the ability in the future to increase production and reserves. There is no assurance that a corporation formed for future acquisitions will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which the Corporation holds an interest, it may suffer a financial loss.

There may be limited liability of residents in the United States to enforce civil remedies.

The Corporation exists under the laws of the Province of Alberta, Canada and has its registered office in Calgary, Alberta, Canada. Some of the Corporation's directors and officers, most of the representatives of the experts who

provide services to the Corporation (such as its auditors and legal counsel), and all or a substantial portion of the assets of such persons are located in Canada. As a result, it may be difficult for investors in the U.S. to effect service of process within the U.S. upon such directors, officers and representatives of experts who are not residents of the U.S. or to enforce against them judgments of the U.S. courts based upon civil liability under the U.S. federal securities laws or the securities laws of any state within the U.S.. There is doubt as to the enforceability in Canada against the Corporation or against any of the Corporation's directors, officers or representatives of experts who are not residents of the U.S., in original actions or in actions for enforcement of judgments of U.S. courts of liabilities based solely upon the U.S. federal securities laws or securities laws of any state within the U.S..

There are differences in reporting practices in Canada and the United States.

The Corporation reports its production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the Securities Exchange Commission by companies in the U.S.. The Corporation incorporates additional information with respect to production and reserves which is either not generally included or prohibited under rules of the Securities Exchange Commission and practices in the U.S.. The Corporation follows the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties). The Corporation also follows the Canadian practice of using forecast prices and costs when estimating reserves; whereas the Securities Exchange Commission requires that prices and costs be averaged for the 12 months as of the date of the reserves report. Included in this Annual Information Form are estimates of proved, and proved plus probable reserves. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. The Securities Exchange Commission generally prohibits the inclusion of estimates of probable reserves in filings made with it. This prohibition does not apply to the Corporation.

As a consequence of the foregoing, the reserve estimates and production volumes in this Annual Information Form may not be comparable to those made by companies utilizing U.S. reporting and disclosure standards.

Forward-Looking Information May Prove Inaccurate

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

Additional information on the risks, assumption and uncertainties are found under the heading "*Forward-Looking Statements*" of this Annual Information Form.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as disclosed below, management is not aware of any material interests, direct or indirect, of directors or executive officers of Mountainview, any holder of Common Shares who beneficially owns or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year which has materially affected or would materially affect Mountainview.

During the year ended December 31, 2014 the Company paid or accrued $6,576,147. (December 31, 2013 $5,619,250) to five companies owned by one of its major shareholders for services provided in the drilling and operating of the wells in the 12-Gage Project. These services have occurred in the normal course of business and are measured at their exchange amount.

During the year ended December 31, 2014, the Company had a joint interest receivable of $76,048 (December 31, 2013 $351,097) from two companies owned by two of its major shareholders. The companies are participants in certain joint venture activities.

During the year ended December 31, 2014, the Company had net a joint interest receivable of $21,031 and had paid or accrued $48,577 (December 31, 2013 - $60,774 and $Nil) from/to three companies owned by a Director and officer in common. The companies are participants in certain joint venture activities.

As of December 31, 2014 the Company executed a purchase and sale agreement for one of the company's non- operated oil and gas assets with a company owned by a major shareholder. Sales proceeds were $400,000 and a loss of $269,149 was recognized on the disposal.

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, valuation or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than Cawley, the Corporation's independent engineering evaluators and PricewaterhouseCoopers LLP, the Corporation's auditors. None of Cawley or the "designated professionals" (as defined in Item 16.2(1.1) of Form 51-102F2 of NI 51-102 of the Canadian Securities Administrators) of Cawley have or are to receive any registered or beneficial interest, direct or indirect, in any of Mountainview's securities or other property of Mountainview or of Mountainview's associates or affiliates, either at the time Cawley prepared the report, valuation, statement or opinion or any time thereafter. PricewaterhouseCoopers LLP are the auditors of the Corporation and have confirmed that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Other than as described below, Mountainview is not a party to any legal proceeding nor was it a party to any legal proceeding during the 2014 financial year, nor is Mountainview aware of any contemplated legal proceeding involving Mountainview, its subsidiaries or any of its property which involves a claim for damages exclusive of interest and costs that may exceed 10% of the current assets of Mountainview.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed) Mountainview has not entered into any material contracts within the last financial year, or before the last financial year which are still in effect.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of Mountainview are PricewaterhouseCoopers LLP, Chartered Accountants, Suite 3100, 111 - 5th Avenue SW, Calgary Alberta T2P 5L3.

Computershare Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario is the transfer agent and registrar of the Common Shares.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the

Corporation's information circular for the Corporation's most recent annual meeting of securityholders that involved the election of directors. Additional financial information is contained in the Corporation's financial statements and the related management's discussion and analysis for the Corporation's most recently completed financial year. For copies of our information circular, our comparative financial statements, including any interim comparative financial statements and additional copies of the Annual Information Form please contact:

Mountainview Energy Ltd.
P.O. Box 200
33 First Avenue SW
Cut Bank, Montana 59427-0200
Tel: (406) 873-2235
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SCHEDULE "A"
STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION



STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

FORM 51-101F1

Effective December 31, 2014

April 29, 2015

CERTAIN DEFINITIONS

This statement of reserves data and other oil and gas information (the "**Statement**") of Mountainview Energy Inc. ("**Mountainview**" or the "**Company**") uses the following definitions from the report ("**Cawley Report**") prepared by Cawley, Gillespie & Associates, Inc. ("**Cawley**"), as described herein. Reference is made herein to the Petroleum Resources Management System approved by the Society of Petroleum Engineers (SPE) Board of Directors, March 2007. Reference is made herein to the Petroleum Reserves and Resources Classification, Definitions and Guidelines jointly published in 2007 by SPE, the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG), and the Society of Petroleum Evaluation Engineers (SPEE), hereinafter denoted as the SPE-PRMS Definitions. The definitions have been prepared by the Standing Committee on Reserves Definitions of the Petroleum Society of the CIM, incorporated in the Society of Petroleum Evaluation Engineers' Canadian Oil and Gas Evaluation Handbook ("**COGE Handbook**") and specified by National Instrument 51-101 – *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**").

RESERVES

"**Reserves**" are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from the given date forward under defined conditions. Reserves must satisfy four criteria: they must be discovered, recoverable, commercial, and remaining based on the development project(s) applied. Reserves are further subdivided in the accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their development and production status. To be included in the Reserves class, a project must be sufficiently defined to establish its commercial viability. There must be a reasonable expectation that all required internal and external approvals will be forthcoming, and there is evidence of firm intention to proceed with development within a reasonable time frame.

A reasonable time frame for the initiation of development depends on the specific circumstances and varies according to the scope of the project. While 5 years is recommended as a benchmark, a longer time frame could be applied where, for example, development of economic projects are deferred at the option of the producer for, among other things, market-related reasons, or to meet contractual or strategic objectives. In all cases, the justification for classification as Reserves should be clearly documented.

To be included in the Reserves class, there must be a high confidence in the commercial producibility of the reservoir as supported by actual production or formation tests. In certain cases, Reserves may be assigned on the basis of well logs and/or core analysis that indicate that the subject reservoir is hydrocarbon-bearing and is analogous to reservoirs in the same area that are producing or have demonstrated the ability to produce on formation tests.

"**On Production**": The development project is currently producing and selling petroleum to market.

The key is that the project is receiving income from sales, rather than the approved development project necessarily being complete. This is the point at which the project "chance of commerciality" can be said to be 100%. The project "decision gate" is the decision to initiate commercial production from the project.

"**Approved for Development**": All necessary approvals have been obtained, capital funds have been committed, and implementation of the development project is under way.

At this point, it must be certain that the development project is going ahead. The project must not be subject to any contingencies such as outstanding regularity approvals or sales contracts. Forecast capital expenditures should be included in the reporting entity's current or following year's approved budget. The project "decision gate" is the decision to start investing capital in the construction of production facilities and/or drilling development wells.

"**Justified for Development**": Implementation of the development project is justified on the basis of reasonable forecast commercial conditions at the time reporting, and there are reasonable expectations that all necessary approvals/contracts will be obtained. In order to move this level of project maturity, and hence have reserves associated with it, the development project must be commercially viable at the time of reporting, based on the reporting entity's assumptions of future prices, costs, etc. ("forecast case") and the specific circumstances of the project. Evidence of a firm intention to proceed with development within a reasonable time frame will be sufficient

to demonstrate commerciality. There should be a development plan in sufficient detail to support the assessment of commerciality and a reasonable expectation that any regularity approvals or sales contracts required prior to project implementation will be forthcoming. Other than such approvals/contracts, there should be no known contingencies that could preclude the development from proceeding within a reasonable timeframe (see Reserves class).

The project "decision gate" is the decision by the reporting entity and its partners, if any, that the project has reached a level of technical and commercial maturity sufficient to justify proceeding with development at that point in time.

DEVELOPED RESERVES

Developed Reserves are expected quantities to be recovered from existing wells and facilities.

Reserves are considered developed only after the necessary equipment has been installed, or when the costs of a well. Where required facilities become unavailable, it may be necessary to reclassify Developed Reserves as Undeveloped. Developed Reserves may be further sub-classified as Producing or Non-Producing.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

"**Developed Non-Producing Reserves**": Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from the zones in existing wells which will require additional completion work or future re-completion prior to start of production.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

UNDEVELOPED RESERVES

Undeveloped Reserves are expected quantities expected to be recovered through future investments:

(1) from new wells on un-drilled acreage in known accumulations, (2) from deepening existing wells to a different (but known) reservoir, (3) from infill wells that will increase recovery, or (4) where a relatively large expenditure (e.g. when compared to the cost of drilling a new well) is required to (a) re-complete and existing well or (b) install production or transportation facilities for primary or improved recovery projects.

PROVED RESERVES

Proved Reserves are those quantities of petroleum, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from given date forward, from known reservoirs and under defined economic conditions, operating method, and government regulations.

If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that quantities will recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

The area of the reservoir considered as Proved includes (1) the area delineated by drilling and defined by fluid contacts, if any, and (2) adjacent undrilled portions of the reservoir that can reasonably be judged as continuous with it and commercially productive on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, Proved quantities in a reservoir are limited by the lowest known hydrocarbon (LKH) as seen in a well penetration unless otherwise indicated by definitive geoscience, engineering, or performance data. Such definitive information may include pressure gradient analysis and seismic indicators. Seismic data alone may not be sufficient to define fluid contacts for Proved reserves (see "2001 Supplement Guidelines", Chapter 8).

Reserves in undeveloped locations may be classified as Proved provided that:

- The locations are in undrilled areas of the reservoir that can be judged with reasonable certainty to be productive.

- Interpretations of available geoscience and engineering data indicate with reasonable certainty that the objective formation is laterally continuous with the drilled Proved locations.

For Proved Reserves, the recovery efficiency applied to these reservoirs should be defined based on a range of possibilities supported by analogs and sound engineering judgment considering the characteristics of the Proved area and the applied development program.

PROBABLE RESERVES

Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves.

It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.

Probable Reserves may be assigned to areas of a reservoir adjacent to Proved where data control or interpretations of available data are less certain. The interpreted reservoir continuity may not meet the reasonable certainty criteria.

Probable estimates also include incremental recoveries associated project recovery efficiencies beyond that assumed for Proved.

The 2P estimates may be based on reasonable alternative technical and commercial interpretations within the reservoir and/or subject project that are clearly documented, including comparisons to results in successful similar projects.

In conventional accumulations, Probable Reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from Proved areas by minor faulting or other geological discontinuities and have not been penetrated by a wellbore but are interpreted to be in communication with the known (Proved) reservoir. Probable Reserves may be assigned to areas that are structurally higher than the Proved area. In some cases, Probable Reserves may be assigned to areas that structurally lower than the adjacent Proved or 2P area.

Caution should be exercised in assigning Reserves to adjacent reservoirs isolated by major, potentially sealing, faults until this reservoir is penetrated and evaluated as commercially productive. Justification for assigning Reserves in such cases should be clearly documented. Reserves should not be assigned to areas that are clearly separated from known accumulation by non-productive reservoir (i.e. absence of reservoir, structurally low reservoir, or negative test results); such areas may contain Prospective Resources.

In conventional accumulations, where drilling has defined a highest known oil (HKO) elevation and there exists the potential for an associated gas cap, Proved oil Reserves should only be assigned in the structurally higher portions of the reservoir if there is reasonable certainty that such portions are initially above bubble point pressure based on documented engineering analyses. Reservoir portions that do not meet this certainty may be assigned as Probable oil and/or gas based on reservoir fluid properties and pressure gradient interpretations.

Other criteria that must also be met for the categorization of reserves are provided in Section 5.5 of the COGE Handbook.

All dollar amounts herein are in US dollars, unless otherwise stated.

ABBREVIATIONS

Oil and Natural Gas Liquids

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

Natural Gas

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

Other

CBM	means coalbed methane
BOE or boe	means barrel of oil equivalent, using the conversion factor of 6 Mcf: 1 bbl
Mboe	means thousand barrels of oil equivalent
MMboe	means million barrels of oil equivalent
boe/d	means barrels of oil equivalent per day
WTI	means West Texas Intermediate
psi	means pounds per square inch

The term "boe" or barrels of oil equivalent may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 Mcf: 1 bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

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

CONVERSION

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
bbls	cubic metres	0.159
cubic metres	Bbls	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
Gigajoules	MMbtu	0.950

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION OF MOUNTAINVIEW ENERGY LTD.

Effective December 31, 2014

FORM 51-101F1

Part 1 Date of Statement
Item 1.1 Relevant Dates

This Statement is dated April 29, 2015. The effective date of the Statement is December 31, 2014 unless otherwise indicated and the preparation date of the Statement is March 24**,** 2015.

Part 2 Disclosure of Reserves Data

In accordance with NI 51-101, the reserves data of the Company as set forth below (the "**Reserves Data**") is based upon an independent evaluation by Cawley with an effective date of December 31, 2014 contained in the Cawley Report.

All evaluations of future revenue are after the deduction of future income tax expenses, unless otherwise noted in the tables, royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of the Company's reserves. There is no assurance that the forecast price and cost assumptions contained in the Cawley Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the Cawley Report. The recovery and reserves estimates on the Company's properties described herein are estimates only. The actual reserves on the Company's properties may be greater or less than those calculated.

All of the Company's reserves are in the United States and, specifically, in Montana and North Dakota.

Item 2.1 Reserves Data (Forecast Prices and Costs—ALL $ values are in $US unless stated otherwise)

Table 2.1.1 "Summary of Oil and Gas Reserves as of December 31, 2014" discloses, in the aggregate, the Company's gross and net proved reserves, probable reserves and proved plus probable reserves, estimated using forecast prices and costs, by product type. "Forecast prices and costs" are future prices and costs that are "generally accepted as being a reasonable outlook of the future".

Table 2.1.2 "Summary of Net Present Values of Future Net Revenue as of December 31, 2014" discloses, in the aggregate, the net present value of the Company's future net revenue attributable to the reserves categories in Table 2.1.1, estimated using forecast prices and costs, before and after deducting future income tax expenses, and calculated without discount and using discount rates of 5%, 10%, 15% and 20%.

Table 2.1.3 "Total Future Net Revenue (Undiscounted) as of December 31, 2014" discloses, in the aggregate, certain elements of the Company's future net revenue attributable to its proved reserves and its proved plus probable reserves, estimated using forecast prices and costs, and calculated without discount.

Table 2.1.4 "Future Net Revenue by Production Group as of December 31, 2014" discloses, by production group, on a unit value basis, the net present value of the Company's future net revenue attributable to its proved reserves and its proved plus probable reserves, before deducting future income tax expenses, estimated using forecast prices and costs, and calculated using a 10% discount rate.

Table 2.1.5 "Forecast Prices and Costs" includes any fixed or presently determinable future prices or costs to which the Company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended. In effect, such contractually committed prices override benchmark reference prices for the purpose of estimating reserves data. As at December 31, 2014, the Company has not entered into any contractual or other obligation to supply a physical product.

Table 2.1.1
SUMMARY OF OIL AND GAS RESERVES
as of December 31, 2014
FORECAST PRICES AND COSTS

	Reserves					
	Light and Medium Oil		Natural Gas		Total Barrels Oil Equivalent	
	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mboe)	Net (Mboe)
Proved Developed Producing	1,697.4	1,414.2	1554.0	1,264.2	1,956.4	1,624.9
Proved Developed Non-Producing	207.9	166.3	155.9	124.7	233.9	187.1
Proved Undeveloped	4,739.5	3,793.7	3,577.1	2,864.5	5,335.7	4,271.1
Total Proved	6,644.8	5,374.2	5,287.0	4,253.4	7,526.0	6,083.1
Total Probable	5,032.5	4,028.8	3,833.8	3,070.6	5,671.5	4,540.6
Total Proved Plus Probable	11,677.3	9,403.0	9,120.8	7,324.0	13,197.4	10,623.7

1) Note: All reserves are located in the U.S.

Table 2.1.2
SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2014
FORECAST PRICES AND COSTS

	Before Income Taxes Discounted At (%/year)					After Income Taxes Discounted At (%/year)					Before Tax Net Value 10%/yr ($/boe)
	0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	0% ($000's)	5% ($000's)	10% ($000's)	15% ($000's)	20% ($000's)	
Proved Developed Producing	37,632	32,102	26,657	22,568	19,537	33,021	29,373	24,966	21,466	18,778	13.63
Proved Developed Non-Producing	5,052	3,535	2,623	2,022	1,593	4,194	3,059	2,341	1,844	1,474	11.21
Proved Undeveloped	72,647	34,653	14,888	3,948	-2,396	47,839	21,641	7,710	-114	-4,685	2.79
Total Proved	115,331	70,290	44,168	28,538	18,734	85,054	54,073	35,017	23,196	15,567	5.87
Total Probable	110,783	51,834	25,220	12,340	5,787	70,614	32,410	15,199	6,941	2,805	4.45
Total Proved Plus Probable	226,114	122,124	69,388	40,878	24,521	155,668	86,483	50,216	30,137	18,372	5.26

Table 2.1.3
TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2014
FORECAST PRICES AND COSTS

	Revenue ($000's)	Royalties ($000's)	Operating Costs ($000's)	Development Costs ($000's)	Abandonment and Reclamation Costs ($000's)	Future Net Revenue Before Future Income Taxes ($000's)	Future Income Taxes ($000's)	Future Net Revenue After Future Income Taxes ($000's)
Total Proved	607,583	176,775	160,120	99,560	5,337	115,331	30,277	85,054
Total Proved Plus Probable	1,106,173	321,709	257,570	199,483	8,362	226,114	70,446	155,668

Table 2.1.4
FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2014
FORECAST PRICES AND COSTS

	Production Group	Future Net Revenue Before Future Income Taxes (Discounted at 10%/Year) ($000's)	Unit Value Before Future Income Taxes Discounted at 10%/Year $/BOE
Total Proved	Light and medium crude oil (including solution gas and associated by-products)	40,325	7.5
	Natural Gas (including associated gas by-products but excluding solution gas and by-products from oil wells)	3,843	0.9
	Total	44,168	8.4
Total Proved Plus Probable	Light and medium crude oil (including solution gas and associated by-products)	63,351	6.7
	Natural Gas (including associated gas by-products but excluding solution gas and by-products from oil wells)	6,037	0.8
	Total	69,388	7.6

PART 3 PRICING ASSUMPTIONS

Forecast Prices Used in Estimates

The following table sets forth the benchmark reference prices, as at December 31, 2014, reflected in the Reserves Data. These price assumptions were provided to the Company by Cawley and were Cawley's then current forecasts at the date of the Cawley Report.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS[(1)]
as at December 31, 2014
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/bbl)	Natural Gas Henry Hub Gas Prices ($US/ MMbtu)	Inflation Rate %/Year
2015	65.00	3.25	1.5
2016	80.00	3.75	1.5
2017	90.00	4.00	1.5
2018	91.35	4.50	1.5
2019	92.72	5.00	1.5
2020	94.11	5.08	1.5
2021	95.52	5.15	1.5
2022	96.96	5.23	1.5
2023	98.41	5.31	1.5
2024	99.89	5.39	1.5
2025	101.39	5.47	1.5
Thereafter	1.50%	1.50%	1.50%

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a *reporting issuer*.

Unaudited, weighted average historical prices, including hedging, realized by the Company for the year ended December 31, 2014, were $80.30/bbl for crude oil and $2.58/Mcf for natural gas.

PART 4 RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 Reserves Reconciliation

The following table sets forth a reconciliation of the Company's total gross proved, total gross probable and total gross proved plus probable reserves as at December 31, 2014 against such reserves as at December 31, 2013 based on forecast prices and cost assumptions.

Table 4.1
RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE
as of December 31, 2014
FORECAST PRICES AND COSTS

	Light and Medium Oil			Associated and Non-Associated Gas			Barrels of Oil Equivalent		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)
12/31/2013	5,963	4,178	1,0141	4,879	3,072	7,951	6,776	4,690	11,466
EXTENSIONS	640	0	640	480	0	480	720	0	720
IMPROVED RECOVERY	1,458	747	2,204	1,139	637	1,776	1,648	853	2,500
INFILL DRILLING	13	0	13	13	0	13	15	0	15
TECHNICAL REVISIONS	-1,153	50	-1,103	-962	81	-881	-1,313	64	-1,250
DISCOVERIES	8	0	8	5	0	5	9	0	9
ACQUISITIONS	34	103	137	26	78	104	38	116	154
DISPOSITIONS	-12	0	-12	-16	0	-16	-15	0	-15
ECONOMIC FACTORS	-11	0	-11	-9	0	-9	-13	0	-13
PRODUCTION	-295	-45	-340	-268	-34	-302	-340	-51	-390
12/31/2014	6,645	5,033	11,677	5,287	3,834	9,121	7,526	5,671	13,197

1) Note: All reserves are located in the U.S.

PART 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

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

As set forth in the tables below, the Company has proved undeveloped reserves and plans to develop all of the proved undeveloped reserves over the next five years. The development program is contingent on obtaining sufficient capital.

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

The following tables sets forth the gross volumes of proved undeveloped reserves and probable undeveloped reserves that were attributed for each of the Company's product types for the most recent three financial years and, in the aggregate, before that time.

Table 5.1.1
SUMMARY OF PROVED UNDEVELOPED RESERVES (GROSS)
as of December 31, 2014
FORECAST PRICES AND COSTS

	Light and Medium Oil (Mbbls)		Natural Gas (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	0	0	0	0
December 31, 2012	0	0	0	0
December 31, 2013	0	3,898	0	2,829
December 31, 2014	3,898	4,739	2,829	3,577

Table 5.1.2
SUMMARY OF PROBABLE UNDEVELOPED RESERVES
as of December 31, 2014
FORECAST PRICES AND COSTS

	Light and Medium Oil (Mbbls)		Natural Gas (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	0	0	0	0
December 31, 2012	0	0	0	0
December 31, 2013	204	4,178	0	3,071
December 31, 2014	4,178	5,032	3,071	3,833

Item 5.2 Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering and economic data. As circumstances change and additional data becomes available, reserve estimates also change. Estimates 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 government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production.

The Company does not anticipate any significant economic factors or significant uncertainties will affect any particular components of this statement. However, reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond the Company's control.

Item 5.3 Future Development Costs

The following table sets forth the development costs deducted in the estimation of future net revenue attributable to proved reserves (using forecast prices and costs) and proved plus probable reserves (using forecast prices and costs) based upon the Cawley Report.

Table 5.3.1
FUTURE DEVELOPMENT COSTS
Undiscounted
FORECAST PRICES AND COSTS

Year	Total Proved Estimated Using Forecast Prices and Costs ($000's)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs ($000's)
2015	12,425	13,723
2016	15,291	16,025
2017	36,534	36,534
2018	27,116	27,116
2019	8,180	31,121
Remaining Years	0	74,950
Total for all years undiscounted	81,630	181,553

Mountainview expects to use a combination of internally generated cash from operations, working capital and the issuance of new equity or debt where and when it believes appropriate to fund future development costs set out in the Cawley Report. There can be no guarantee that funds will be available or that the board of directors of the Company will allocate funding to develop all of the reserves attributable in the Cawley Report. Failure to develop those reserves could have a negative impact on the Company's future cash flow.

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

Note: All reserves are located in the U.S.

Part 6 Other Oil and Gas Information

Item 6.1 Oil and Gas Properties and Wells

Property Descriptions

The following property descriptions are as of December 31, 2014 unless otherwise noted and reserves quoted are as reported in the Cawley Report. Each of the following properties are located onshore.

Williston Basin, USA

12 Gage

Mountainview own a 100% working interest in ~14,000 net acres located in the 12 Gage prospect located in Divide County, North Dakota. Mountainview commenced a six well drilling program in 2013 and has now drilled 11 wells (8.12 Gross and 6.52 Net) and completed nine of those wells; with two wells awaiting completion as at December 31, 2014. The following are the results of the 2014 drilling & completion program:

					Average Daily Rates (Total--8/8ths)	
Well	**Spud Date**	**Completion Date**	**Lateral Length (ft)**	**Frac Stages**	**30 Day IP (boe/d)**	**60 Day IP (boe/d)**
Reistad 23-14-1H	11/30/2013	3/4/2014	9,880	32	256	230
Reistad 26-35S-1H	12/2/2013	3/12/2014	10,175	32	398	372
BJNJ 30-31-1H	8/16/2014	10/17/2014	9,453	36	568	513
BJNJ 19-18N-1H	7/16/2014	Standing	10,100	36 planned	N/A	N/A
Aaberg 8-5N-1H	9/9/2014	Standing	10,030	36 planned	N/A	N/A

Medicine Lake (Non-Op) Properties

Mountainview currently holds a non-operated working interest in 18 total wells within the Medicine Lake Property (Mountainview Non-Op). These interests vary from as low as 1% to as high as 3.25%. Mountainview participated in 6 new wells in 2014; divested its interest in 1 well (Olson 1-21-16H), and suspended its interest in 1 well (Orville Hendrickson 12-24H) upon further review of the participation agreement for this well.

The Medicine Lake asset is also comprised of undeveloped acreage located in Divide and Williams County, North Dakota and Roosevelt and Sheridan County, Montana. This asset currently consists of ~11,700 gross (1,500 net) undeveloped acres.

South Alberta Basin, USA

Red Creek

Mountainview owns a 100% working interest in approximately 2,500 net acres located within the Red Creek Property, located in Glacier County, Montana. Mountainview intends to continue its workover and development program in the Red Creek area, with a few existing wells to be brought back on stream. The Company will plan to drill replacement wells in this field as economically feasible.

Lake Frances

The Lake Frances Project is comprised 37,830 gross (32,191 net) acres of petroleum and natural gas lands, of which 4,000 gross (3,750 net) acres have been developed with 25 gross (18.75 net) wells drilled on 160 acre spacing. The total acreage, including an undeveloped area totaling 33,830 gross (28,441 net) acres is located in Pondera County, Montana. While the acreage is not all contiguous, it is anticipated that the development will continue on a 160 acre spacing basis. Development on this property will not commence until there is an increase in the price of natural gas.

Williams

The Williams Project is comprised 18,273 gross (14,922 net) acres of petroleum and natural gas lands, of which 11,520 gross (11,520 net) acres have been developed with 18 gross (18 net) wells drilled on 640 acre spacing. The total acreage, including an undeveloped area encompassing 6,753 gross (3,402 net) acres is located in Pondera County, Montana. The acreage is relatively contiguous, thus development will continue, however development is expected to be effected on a 320 acre spacing basis rather than the existing 640 acres. Development on this property will not commence until there is an increase in the price of natural gas.

Loneman Coulee (Fields / Jody Fields Wells)

Effective August 31, 2010, the Company accepted assignment of all of Altamont Oil & Gas, Inc.'s right, title and interest in the Loneman Coulee located in Pondera County which consists of 1,718 acres. Located within this acreage are four wells that the Company operates. One well currently produces, 1 well is shut in, and the other two wells serve as water disposal wells.

Donovan / Pondera

Mountainview entered into a farm-out agreement with Majestic Oil & Gas, Inc. on September 1, 2009, outlining parameters for Mountain View Energy, Inc., a wholly-owned subsidiary of Mountainview, to drill a test well in the NWSE-Section 33-T27N-R4W, Teton County, Montana at its sole cost, risk and expense. In doing so, Mountain View Energy, Inc., acquired 75% of the working interest, while Majestic Oil & Gas, Inc. retained a 25% working interest in any well drilled in the 40-acre tract.

Two wells were drilled and completed on this property in 2009 and both wells continue to produce to-date. There are no current plans to further develop this property.

Snoose Coulee

Effective April 1, 2010 the Company acquired 100% of a third party's 30% right, title and interest in the Snoose Coulee Field located in Liberty County, Montana for $55,000 included with this acquisition. Working and royalty interest in 14 natural gas wells.

The following table sets forth the number and status of wells in which the Company held a working interest as at December 31, 2014:

	Oil Wells		Natural Gas Wells	
	Gross	**Net**	**Gross**	**Net**
Red Creek				
Producing	33	30	-	-
Non-producing	3	2	-	-
Williams				
Producing	-	-	20	16
Non-Producing	-	-	1	1
Lake Frances				
Producing	-	-	24	18.75
Non-Producing	-	-	-	-
Loneman Coulee				
Producing	1	0.5	-	-
Non-Producing	3	1.5	-	-
Pondera/Donovan				
Producing	2	1.5	-	-
Non-Producing	1	-	-	-
Snoose Coulee				
Producing	-	-	13	4.29
Non-Producing	-	-	1	0.33
Medicine Lake (Non-Op)				
Producing	19	0.38	-	-
Non-Producing	-	-	-	-
12-Gage				
Producing	12	7.49	-	-
Non-Producing	2	-	-	-
TOTALS:	**76**	**48.37**	**57**	**41.37**

Item 6.2 Properties with No Attributed Reserves

The following table sets out the Company's unproved property land holdings as at December 31, 2014.

	Undeveloped Acres	
	Gross	**Net**
Medicine Lake Roosevelt & Sheridan County, MT & Williams & Divide County, ND	11,720	1,448
12-Gage Divide County, ND	6,173	3,585
South Alberta Bakken	37,854	33,027
Total	55,748	38,060

The Company holds multiple well bonds in both Montana and North Dakota. In addition, the Company is subject to drilling timelines based on the lease expiries. Under the 12-Gage property, the Company owns 100% of mineral interests in ~14,000 net acres from surface to the top of the Bird Bear formation. In addition, the Company is restricted to a ~20% interest in 5,693 acres below the top of the Bird Bear formation. In certain sections of land, the acreage is broken down into tracts within the drilling spacing unit ("DSU"). Mountainview does not have a working interest in some of these tracts. When a well is proposed in a DSU, the minority working interest owners become non-operated working interest partners if they elect to participate in the well. If such an election is made, the result is a lesser working interest in the overall DSU. Gross undeveloped acres represent the total drillable acreage in a DSU, while net acreage represents Mountainview's working interest position in those spacing units.

In 2015, there are 7,603 gross undeveloped acres (798 net) expiring in Medicine Lake, 6,111 gross undeveloped acres (3,523 net) expiring in 12 Gage, and 6,688 gross undeveloped acres (6,115 net) expiring in the South Alberta Bakken.

Item 6.2.1 Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

The significant factors or uncertainties relevant to the properties with no attributed reserves are: commodity prices, regulations over hydraulic fracturing and insufficient funding to undertake development.

Item 6.3 Forward Contracts

As at December 31, 2014, Mountainview was 12 months into an eighteen month hedging agreement with forward selling products. The hedging agreement has a collar with a floor at $85 and the ceiling at $97.70. The agreed barrels per months are as follows:

Month Rage	Barrels
Jan. – Mar. 2014	11,000
Apr. – June 2014	9,000
Jul. – Dec. 2014	6,000
Jan. – June 2015	4,000

Item 6.4 Additional Information Concerning Abandonment and Reclamation Costs

Mountainview uses an estimated authorization for expenditure (AFE) based on current industry costs and current plugging and abandoning regulations established by the Montana Board of Oil and Gas "MBOG" and the North Dakota Industrial Commistion "NDIC" average for abandonment costs. This cost is $17,500 per well for shallow oil wells in northwestern Montana—Legacy properties, and $8,500 per gas well in the Lake Frances, Williams, and Snoose Coulee fields. The abandonment costs for deep horizontal wells (all properties in the Mountain Divide and Non-Op (Medicine Lake) subcategory) in the Williston Basin is estimated at $168,000 per well. These estimated abandonment costs do include site reclamation for wells and facilities.

Mountainview estimates that it will incur no reclamation and abandonment costs during the upcoming year of 2015. The wells currently shut-in are being evaluated to be returned to production based on current and projected future economic conditions.

Mountainview Energy currently holds interest in 122 gross / 90 net producing wells. The approximate net cost to abandon and reclaim all wells and facilities, discounted at 10%, totals $1.8 million ($3.6 million undiscounted), of which 100% is included in the estimate of future net revenue**.** Abandonment and reclamation costs undiscounted and expected to be paid over the next three years total an estimated $100,000.

Item 6.5 Tax Horizon

The Company is subject to tax in the State of Montana and North Dakota, along with US Federal Income Tax. The Company was not in a taxable position as at December 31, 2014. Under the existing US Federal tax laws, Mountainview elects to use Intangible Drilling Credits ("**IDCs**") when filing annual tax returns. When combined with its annual depletion allowance, Mountainview does not anticipate being in a taxable position until 2020. When compiling this reserve evaluation, Cawley evaluated the reserves taking IDCs and depletion allowance into account. The company has approximately $8.0 million in deferred tax assets at December 31, 2014. The impact of US Federal tax and State tax in the State of Montana and State of North Dakota has been calculated and is included in the analysis of reserve values. The tax impact on Total Proved reserves is $30.3 million, and the impact on Total Proved plus Probable reserves is $70.4 million (discounted).

Item 6.6 Costs Incurred

The following table summarizes the unaudited capital expenditures made by the Company on oil and natural gas properties for the year ended December 31, 2014

Property Acquisition Costs ($000's)		Exploration Costs ($000's)	Development Costs ($000's)
Proved Properties	Unproved Properties		
44		7,800	11,270

Item 6.7 Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which the Company completed as operator during its 2014 financial year:

	Exploratory Wells		Development Wells	
	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]
Oil Wells	1	0.99	2	1.60
Gas Wells	-	-	-	-
Service Wells	-	-	-	-
Stratigraphic Test Wells	-	-	-	-
Dry Holes	-	-	-	-
Total Completed Wells	1	0.99	2	1.6

Notes:

(1) "Gross" means the total number of wells in which the Company has an interest.
(2) "Net" means the number of wells obtained by aggregating the Company's interest in each of its gross wells.
(3) All wells are located in the U.S.

See also *Property Descriptions* for a description of Mountainview's current and proposed exploration and development activities.

Item 6.8 Production Estimates

The following table sets forth for each product type the volume of production estimated for the year ending December 31, 2015, which is reflected in the estimates of gross proved reserves and gross probable reserves disclosed under Item 2.1 – *Reserves Data (Forecast Prices and Costs)*.

	Gross Proved		Gross Probable	
	Light and Medium Oil (Mbbl)	Natural Gas (MMcf)	Light and Medium Oil (Mbbl)	Natural Gas (MMcf)
Mountainview Legacy [(1)]	28.9	65.2	0	0
Mountain Divide (Prev.12 Gage)	262.9	183.1	0	0
Mountainview Non-Op (Prev Med Lake)	12.3	9.8	5.2	5.2
Total	304.1	258.1	5.2	5.2

1) MVE Legacy is a combination of Pondera, Loneman Coulee, Snoose Coulee, Lake Frances, Red Creek & Williams Properties

Item 6.9 Production History (Gross)

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

	Quarter Ended 2014				Year Ended
	Mar. 31	June 30	Sept. 30	Dec. 31	Dec. 31, 2014
Average Daily Production(1)					
Oil (bbls/d)	930.8	935.6	764.8	1,023.80	913.7
Gas (Mcf/d)	859.4	841	736.4	810.6	811.8
Combined (boe/d)	1,074.0	1,075.7	887.5	1,158.90	1,049.0
Average Net Production Prices Received					
Oil ($/bbl)	86.68	90.14	83.38	61.01	80.30
Gas ($/Mcf)	2.87	2.87	2.55	2.04	2.58
Combined ($/boe)	103.90	107.36	98.68	73.25	95.78
Royalties Paid					
Oil ($/bbl)	12.94	14.64	14.31	9.43	12.83
Gas ($/Mcf)	0.17	0.20	0.29	0.20	0.21
Combined ($/boe)	13.96	15.84	16.05	10.63	14.09
Operating Expenses					
Oil ($/bbl)	17.22	24.61	27.58	21.05	22.61
Natural gas ($/Mcf)	2.84	4.79	4.62	4.35	4.15
Combined ($/boe)	17.19	25.14	27.60	21.58	22.88
Netback Received					
Oil ($/bbl)	56.52	50.89	41.49	30.53	44.86
Gas ($/Mcf)	-0.14	-2.12	-2.36	-2.51	-1.78
Combined ($/boe)	72.75	66.38	55.03	41.04	58.81

Notes:

(1) Before deduction of royalties.

The following table indicates the Company's approximate average daily production from its important fields for the year ended December 31, 2014:

Item 6.10 Production History (Gross by Business Unit / Field)

Properties	Light and Medium Oil (bbls/d)	Natural Gas (Mcf/d)	Total (boe/d)
Mountain Divide (12 Gage)	676.5	437.8	749.5
Legacy (Red Creek)	87.2	0.0	87.2
Legacy (Williams & Lake Frances)	0.0	233.4	38.9
Legacy (Snoose Coulee)	0.0	50.0	8.3
Legacy (Pondera)	2.1	0.0	2.1
Legacy (Loneman Coulee)	0.8	0.0	0.8
Non-Op (Medicine Lake)	24.6	20.4	28.0
Total	791.2	741.6	914.8

SCHEDULE "B"
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the board of directors of Mountainview Energy Ltd.:

1. We have evaluated Mountainview Energy Ltd.'s reserves data as of December 31, 2014. The reserves data consists of estimates of proved and probable reserves and related future revenue as of December 31, 2014 using forecast prices and costs.

2. The reserves data are the responsibility of Mountainview Energy Ltd.'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 ("COGEH"), 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 COGEH.

4. The following table sets forth the estimated future 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 Mountainview Energy Ltd. evaluated by us as of December 31, 2014 and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to Mountainview Energy Ltd.'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$)	Total (M$)
Cawley, Gillespie & Associates, Inc.	Total Proved Plus Probable Reserves of Mountainview Energy Ltd. in certain oil and gas properties in Montana and North Dakota, As of December 31, 2014, prepared December 2014 to March 2015	USA		69,388.6		69,388.6
Total			**Nil**	**69,388.6**	**Nil**	**69,388.6**

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

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after its preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

Cawley, Gillespie & Associates, Inc.
Texas Registered Engineering Firm F-693
Fort Worth, Texas
March 30, 2015



Robert D. Ravnaas, P.E.
President

SCHEDULE "C"
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

REPORT OF MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION

FORM 51-101F3

Management of Mountainview Energy Ltd. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The 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 approved:

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

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

(c) the content and filing of this report.

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

(signed) "*Patrick M. Montalban*"	(signed) "*Brent A. Osmond*"
Patrick M. Montalban	Brent A. Osmond
President and Chief Executive Officer	Vice President, Finance and Chief Financial Officer
(signed) "*Keith Macdonald*"	(signed) "*Bo Mikkelsen*"
Keith Macdonald	Bo Mikkelsen
Director	Director

April 29, 2015

SCHEDULE "D"
AUDIT COMMITTEE MANDATE



AUDIT COMMITTEE CHARTER

Introduction

Mountainview Energy Ltd. (the "**Corporation**") is a Montana based junior oil and gas exploration and development company. The Board of Directors of the Corporation (the "**Board**") has the responsibility for the overall stewardship of the conduct of the business of the Corporation and the activities of management of the Corporation, which is responsible for the day-to-day conduct of the business.

Purpose

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

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

(2) To provide better communication between directors and external auditors;

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

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

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

(6) To assist the Board's oversight of the performance of Corporation's internal audit function and external auditors; and

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

Composition, Procedures and Organization

(1) The Committee shall consist of at least three members of the Board of Directors (the "**Board**"), a majority of whom shall be "independent", as that term is defined in Sections 1.4 and 1.5 of Multilateral Instrument 52-110, *Audit Committees* ("**MI 52-110**") (provided that, if the Common Shares of the Corporation (the "**Shares**") are listed and posted on the Toronto Stock Exchange or

registered with the United States Securities and Exchange Commission (the "**SEC**"), then, pursuant to rules of the Toronto Stock Exchange or the requirements of Rule 10A-3 of the Securities Exchange Act of 1934, as amended (the "**Act**"), respectively, all of the members of the Audit Committee shall be "independent").

(2) All of the members of the Committee shall be "financially literate" (i.e. able to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of those of the Corporation and that can be reasonably expected to be raised by the Corporation's financial statements) (provided that, if the Shares are registered with the SEC, then at least one member of the Committee must be an "audit committee financial expert" as defined in Item 407(d)(5)(ii) of Regulation S-K).

(3) The Committee composition, including the qualifications of its members, shall comply with the applicable requirements of stock exchanges on which the Corporation lists its securities and of securities regulatory authorities, as such requirements may be amended from time to time.

(4) The Board shall appoint the members of the Committee. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.

(5) Unless the Board shall have appointed a chair of the Committee, the members of the Committee shall elect a chair from among their members.

(6) The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.

(7) The Committee shall have access to such officers and employees of the Corporation and to the Corporation's external auditors, and to such information respecting the Corporation, as it considers necessary or advisable in order to perform its duties and responsibilities.

(8) Meetings of the Committee shall be conducted as follows:

(a) the Committee shall meet at least four times annually at such times and at such locations as may be requested by the chair of the Committee. The external auditors or any member of the Committee may request a meeting of the Committee;

(b) the external auditors may receive notice of and have the opportunity to attend meetings of the Committee; and

(c) the following management representatives may be invited to attend meetings, except in-camera sessions and private sessions with the external auditors:

President and Chief Executive Officer
Chief Financial Officer

other management representatives may be invited to attend as necessary.

(9) The external auditors shall report directly to the Committee and the external auditors and internal auditors (if any) shall have a direct line of communication to the Committee through its chair and may bypass management if deemed necessary. The Committee, through its chair, may contact directly any employee of the Corporation as it deems necessary, and any employee may bring

before the Committee any matter involving questionable, illegal or improper financial practices or transactions.

(10) The Committee may retain, at the Corporation's expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties and may set and pay the compensation for any advisor engaged. The Committee will notify the Board Chair whenever independent consultants are engaged.

Handling of Complaints

The Committee shall maintain procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters, and the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters (a "**Whistleblower Policy**").

Annual Review

The Committee shall review and assess the adequacy of this Charter annually, report to the Board thereon and recommend any proposed changes to the Board for approval. The Committee shall also perform an annual evaluation of the performance of the Committee and shall report the results of the evaluation to the Board Chair.

Roles and Responsibilities

(1) The overall duties and responsibilities of the Committee shall be as follows:

(a) to assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and its approval of the Corporation's annual and quarterly financial statements and management's discussion and analysis;

(b) to establish and maintain a direct line of communication with the Corporation's internal (if any) and external auditors and assess their performance;

(c) to assist the Board in the discharge of its responsibilities relating to oversight of the Company's internal, financial and disclosure controls and procedures;

(d) to pre-approve all audit and non-audit services to be provided by the Corporation's external auditor and to periodically review the audit and non-audit services pre-approval policy and recommend to the Board any changes which the Committee deems appropriate. The Committee may delegate to one or more members of the Committee authority to pre-approve non audit services in satisfaction of this requirement and if such delegation occurs, the pre-approval of non-audit services by the Committee member to whom authority has been delegated must be presented to the Committee at its first scheduled meeting following such pre-approval. The Committee shall be entitled to adopt specific policies and procedures for the engagement of non-audit services if:

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

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

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

The Committee will satisfy the pre-approval requirement set forth above if:

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

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

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

(e) to periodically consider whether there is a need to outsource internal audit functions or create an internal audit department;

(f) to review the reports to management prepared by the external auditors and management’s responses;

(g) to receive and review complaints received pursuant to the Corporation's Whistleblower Policy and oversee and provide direction on the investigation and resolution of such concerns and to periodically review the said policy and recommend to the Board changes which the Committee may deem appropriate;

(h) to report regularly to the Board on the fulfilment of its duties and responsibilities;

(i) to review significant findings during the year, including the status of previous significant audit recommendations;

(j) to identify and monitor the management of the principal risks that could impact the financial reporting of the Corporation;

(k) to ensure that it satisfies those responsibilities set out in Part 2 of MI 52-110 and provisions contained within the Companion Policy to MI 52-110;

(l) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation; and

(m) institute a policy that requires the signature of a minimum of two designated officers on all cheques written by the Corporation.

(2) The duties and responsibilities of the Committee as they relate to the external auditors shall be as follows:

(a) to be directly responsible for overseeing the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or

attest services for the Corporation, including the resolution of disagreements between management and the external auditors regarding financial reporting;

(b) to (1) select and retain an independent registered public accounting firm to act as the Corporation's external auditors for the purpose of auditing the Corporation's annual financial statements, books, records, accounts and internal controls over financial reporting, subject to ratification by the shareholders of the Corporation of the selection of the external auditors, (2) monitor and verify the independence of such external auditors and (3) terminate the Corporation's external auditors, if necessary;

(c) to review and approve the fee, scope and timing of the audit and other audit related and non-audit services rendered by the external auditors;

(d) review the audit plan of the external auditors prior to the commencement of the audit;

(e) to review with the external auditors, upon completion of their audit:

(i) contents of their report;

(ii) scope and quality of the audit work performed;

(iii) adequacy of the Corporation's financial and auditing personnel;

(iv) co-operation received from the Corporation's personnel during the audit;

(v) internal resources used;

(vi) significant transactions outside of the normal business of the Corporation;

(vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems; and

(viii) the non-audit services provided by the external auditors, as pre-approved pursuant to the audit and non-audit services pre-approval policy;

(f) when there is to be a change in external auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;

(g) to review any unresolved issues between management and the external auditors that could affect the financial reporting or internal controls of the Corporation;

(h) to implement structures and procedures to ensure that the Committee meets the external auditors on a regular periodic in the absence of management;

(i) to receive a written statement from the external auditor describing in detail all relationships between the auditor and the Corporation that may impact the objectivity and independence of the auditor. The Committee shall review with the Board of Directors the independence of the external auditors and either confirms to the Board of Directors that the external auditors are independent or recommend that the Board of Directors take appropriate action to satisfy itself of the external auditor's independence; and

(j) to review and discuss with the Corporation's external auditors (1) all critical accounting policies and practices to be used in the audit; and (2) all alternative treatments of financial information within international financial reporting standards ("**IFRS**") that have been discussed with management, the ramifications of the use of such alternative treatments and the treatment preferred by the auditors.

(3) The duties and responsibilities of the Committee as they relate to the internal control procedures of the Corporation are to:

(a) review the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to insurance, accounting, information services and systems and financial controls, management reporting and risk management;

(b) review compliance under the Corporation's Code of Business Conduct with those matters addressed in the policy which affect the financial integrity of the Corporation and to periodically review this policy, management's monitoring of it, and recommend to the Board changes which the Committee may deem appropriate; and

(c) periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the internal accounting staff or by the external auditors have been implemented.

(4) The Committee is also charged with the responsibility to:

(a) review and recommend to the Board for its approval, the Corporation's financial statements, management's discussion and analysis and annual and interim earnings press releases before the Corporation publicly discloses this information;

(b) review and approve the Corporation's interim financial statements, interim management's discussion and analysis including the impact of unusual items and changes in accounting principles and estimates and report to the Board with respect thereto and interim earnings press releases before the Corporation publicly discloses this information;

(c) review the financial sections of:

(i) the annual report to shareholders;

(ii) prospectuses;

(iii) other public reports containing financial information requiring approval by the Board; and

(iv) press releases related thereto,

and report to the Board with respect thereto;

(d) review regulatory filings and decisions as they relate to the Corporation's financial statements;

(e) review the appropriateness of any written policies and procedures used in the preparation of the Corporation's financial statements and other required disclosure documents, and consider recommendations for any material change to such policies;

(f) review the minutes of any audit committee meeting of any subsidiary of the Corporation;

(g) review with management, the external auditors and, if necessary, with legal counsel, any litigation, 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 such matters have been disclosed in the consolidated financial statements;

(h) review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements and tax matters;

(i) endeavour to ensure all material public documents relating to the financial performance, financial position or analysis thereon are reviewed by the Committee or another appropriate committee, as designated by the Board of Directors. In certain cases, including in respect of "roadshow" or other investor materials, the Committee may designate the responsibility for review to the Chair of the Committee, the Chief Financial Officer of the Corporation or to legal counsel;

(j) The Committee shall review significant changes in the accounting principles to be observed in the preparation of the accounts of the Corporation and its subsidiaries, or in their application, and in financial disclosure presentation; and

(k) The Committee shall review such reports as may be required by any applicable securities regulatory authority to be included in the Corporation's Information Circular or any other disclosure document of the Corporation.

Accountability

The Committee shall report its activities and proceedings to the Board by distributing the minutes of its meetings or by oral or written report at the next Board meeting.

Standards of Liability

Nothing contained in this mandate is intended to expand applicable standards of liability under statutory, regulatory, common law or any other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this mandate are meant to serve as guidelines rather than inflexible rules and the Committee may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.

Annual Review And Assessment

The Committee shall conduct an annual review and assessment of its performance, including compliance with this Charter and its role, duties and responsibilities, and submit such report to the Board of Directors. The Committee shall also update this Charter periodically as conditions dictate.

Committee Timetable

The major activities of the Committee with respect to scheduled meetings will be outlined in an annual schedule, a sample of which can be found attached hereto as Schedule "A".

SCHEDULE "A"

Example of Audit Committee Meeting Agenda for Year

As noted previously, it is important to review the completeness of the Audit Committee charter as well as the agenda established for each meeting. The following is an example of topics that could be covered in each Audit Committee meeting. This example assumes a December 31 year-end with four audit committee meetings scheduled in connection with quarterly earning releases

Charter step		Scheduled Meetings			
		May	**August**	**November**	**March**
I.	**Audit Committee Purpose**				
	Conduct special investigations	*	*	*	*
II.	**Audit Committee Composition and Meetings**				
	Assess independence and financial literacy of Audit Committee			X	
	Establish number of meetings			X	
	Audit Committee Chair to establish meeting agenda			X	
	Enhance financial literacy - update on current financial events	X	X	X	X
	Executive sessions with auditors, management, committee	X	X	X	X
III.	**Audit Committee Responsibilities and Duties**				
1.	Review charter, publish relevant information in proxy			X	
2.	Review annual financial statements - discuss with management, auditors			X	
3.	Consider internal controls and financial risks			X	
4.	Review quarterly results and findings	X	X	X	
5.	Recommend appointment of auditors			X	
6.	Approve audit fees			X	
7.	Discuss auditor independence			X	
8.	Review audit plan			X	
9.	Discuss year-end results				X
10.	Discuss quality of accounting principles	*	*	*	X
11.	Review legal matters with counsel and auditors		*	*	X
12.	Prepare report to shareholders				X
13.	Perform other activities as appropriate	*	*	*	*
14.	Maintain minutes and report to Board of Directors	X	X	X	X
15.	Review Code of Conduct	X	X	X	X
16.	Perform self-assessment of Audit Committee performances				X
17.	Review financial personnel succession planning				X
18.	Review director and officer expenses and related party transactions				X

X = RECOMMENDED TIMING * = AS NEEDED