



ANNUAL INFORMATION FORM
FOR THE YEAR ENDED
DECEMBER 31, 2013

March 21, 2014

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ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	stock tank barrels

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule
GJ/d	gigajoules per day
MM	Million

Other

AECO	the natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas
BOE/d	barrel of oil equivalent per day
m ³	cubic metres
MBOE	1,000 barrels of oil equivalent
Mcfe	thousand cubic feet of gas equivalent
Mcfe/d	thousand cubic feet of gas equivalent per day
MMcfe/d	million cubic feet of gas equivalent per day
\$000s or \$M	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

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 Bellatrix, 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.

All production and reserves quantities included in this Annual Information Form (including the Schedules hereto) have been prepared 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 (as defined herein) by United States companies. Nevertheless, as part of Bellatrix's Annual Report on Form 40-F for the year ended December 31, 2013 filed with the SEC, Bellatrix has disclosed proved reserves quantities using the standards contained in SEC Regulation S-X, and the standardized measure of discounted future net cash flows relating to proved oil and gas reserves determined in accordance with the U.S. Financial Accounting Standards Board, "Disclosures About Oil and Gas Producing Activities", which disclosure complies with the SEC's rules for disclosing oil and gas reserves.

Disclosure provided herein in respect of BOEs or Mcfes may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 Bbl and an Mcfe conversion ratio of 1 Bbl:6 Mcf are based on an energy equivalency conversion method primarily applicable at the burner tip and does 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 6Mcf:1Bbl, utilizing a conversion on a 6Mcf:1Bbl basis may be misleading as an indication of value.

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres (Alberta)	Hectares	0.400
Hectares (Alberta)	Acres	2.500
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471

CERTAIN DEFINITIONS

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

"**4.75% Debenture Indenture**" means the trust indenture dated April 20, 2010 between the Corporation and Computershare Trust Company of Canada governing the terms of the 4.75% Debentures;

"**4.75% Debentures**" means the 4.75% convertible unsecured subordinated debentures of the Corporation issued pursuant to the 4.75% Debenture Indenture;

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

"**Angle**" means Angle Energy Inc.;

"**Angle Arrangement**" means the plan of arrangement completed on December 11, 2013 under the provisions of the ABCA pursuant to an arrangement agreement between Bellatrix and Angle dated October 15, 2013;

"**Angle Debentures**" means the 5.75% convertible unsecured subordinated debentures due January 31, 2016 of Angle;

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

"**Bellatrix**", the "**Corporation**", "**we**", "**us**" or "**our**" means Bellatrix Exploration 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 Bellatrix;

"**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.

"**net**" means:

- (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalties obligations, plus our royalty interest 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 52-101**" means National Instrument 51-102 - *Continuous Disclosure Obligations*;

"**NYSE MKT**" means the NYSE MKT stock exchange;

"**Sproule**" means Sproule Associates Limited;

"**Sproule Report**" means the report of Sproule dated March 4, 2014 evaluating our crude oil, natural gas liquids and natural gas reserves as at December 31, 2013; and

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

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, 2013.

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

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, management plans and assessments of future plans and operations, expectations of the number of additional drilling locations resulting from certain acquisitions, timing of bringing new wells on stream, production estimates, plans with respect to the Corporation's facilities, the expected reductions in operating expenses and access to gas markets resulting from the acquisition of working interests in gas processing facilities in the Ferrier area, drilling and completion plans, plans and timing for development of undeveloped and probable reserves, timing of when the Corporation may be taxable, estimated abandonment and reclamation costs, plans regarding hedging, the number of potential drilling locations, wells to be drilled, the weighting of commodity expenses, and capital expenditures and the nature of capital expenditures and the timing and method of financing thereof, may be forward-looking statements. 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 involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Bellatrix's reserves provided 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.

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 Bellatrix 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 Bellatrix 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 Bellatrix operates; the timely receipt of any required regulatory approvals; the ability of Bellatrix to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which Bellatrix has an interest in to operate the field in a safe, efficient and effective manner; the ability of Bellatrix 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 of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Bellatrix to secure adequate product transportation; 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 Bellatrix operates; and the ability of Bellatrix to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhausted. Additional information on these and other factors that could affect Bellatrix'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), at Bellatrix's website (www.bellatrixexploration.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 Bellatrix 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 concerning the oil and gas industry and Bellatrix's general expectations concerning this industry is based on estimates prepared by management using data from publicly available 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 Bellatrix believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and

performance characteristics. While Bellatrix 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

Bellatrix is a growth oriented oil and gas exploration company based in Calgary which owns and assumed, directly or indirectly, all of the assets and liabilities, respectively, of True Energy Trust pursuant to a plan of arrangement completed on November 1, 2009. Under the plan of arrangement, True Energy Inc. and True Newco Inc. were amalgamated under the ABCA to form a new corporation which was subsequently amalgamated under the ABCA with 1485166 Alberta Ltd. to form Bellatrix.

On December 11, 2013, Bellatrix was amalgamated with Angle and its subsidiary, Angle Resources Inc., under the ABCA and continued under the name "Bellatrix Exploration Ltd." pursuant to the Angle Arrangement.

Bellatrix's principal and head office is located at 1920, 800 – 5th Avenue S.W., Calgary, Alberta, T2P 3T6 and its registered office is located at 2400, 525 – 8th Ave SW Calgary, AB T2P 1G1.

Bellatrix does not have, and at December 31, 2013 did not have, any material subsidiaries.

The Common Shares trade on the TSX and the NYSE MKT under the symbol "BXE".

GENERAL DEVELOPMENT OF OUR BUSINESS

The following is a summary description of the development of our business since January 1, 2011.

2011 Public Offering of Common Shares

On May 11, 2011, the Corporation completed a public offering of an aggregate of 9,822,000 Common Shares at a price of \$5.60 per Common Share for aggregate gross proceeds of \$55,003,200.

2011 Asset Acquisitions and Divestitures

On January 25, 2011, Bellatrix acquired the interest in a section of Frog Lake First Nation lands from a joint venture partner for a net purchase price of \$2.2 million after adjustments. The transaction had an effective date of January 1, 2011. At the time of acquisition, the net production on the acquired lands was 130 BOE/d. The acquisition resulted in Bellatrix acquiring an additional 20% working interest in the Colony formation (Bellatrix already had a 13.75% working interest) and an additional 50% working interest in the McLaren formation (Bellatrix already has a 50% working interest) except for a quarter section (in which Bellatrix already had a 13.75% working interest) in the acquired lands.

On January 25, 2011, Bellatrix exercised a right of first refusal increasing its interest in a joint venture property in the Brazeau area of West Central Alberta for approximately \$1.5 million. The asset acquisition consisted of approximately 3,200 gross (1,102.8 net) acres of Cardium rights providing the Corporation with up to 6.3 additional net Cardium drilling locations and included 15 BOE/d of production.

During the second quarter of 2011, Bellatrix closed two transactions consisting of the sale of a minor property interest of 160 gross (14 net) acres of land in Saskatchewan and a swap of interests where Bellatrix increased its Cardium exposure in 3.5 gross (1.7 net) sections in the Greater Pembina area. There was no production associated with the acreages sold in the second quarter of 2011.

Effective September 22, 2011, the Corporation completed the sale of its interest in a non-core property at Meekwap, Alberta for net proceeds of \$4.2 million after adjustments. The property had production of approximately 65 BOE/d that consisted primarily of light oil.

Listing on the NYSE MKT

On August 30, 2012, Bellatrix announced that it had filed an Original Listing Application to list the Common Shares on the NYSE MKT. In connection with the filing of the Original Listing Application, Bellatrix filed a Registration Statement on Form 40-F with the United States Securities and Exchange Commission. The Common Shares commenced trading on the NYSE MKT on September 24, 2012 under the symbol "BXE".

2012 Asset Acquisitions and Divestitures

On November 15, 2012, Bellatrix acquired prospective Cardium and Notikewin/Falher lands and production in the Willesden Green area of Alberta for approximately \$21 million. The transaction had an effective date of November 1, 2012. At the time of the acquisition, the assets to be acquired had production capability of approximately 500 BOE/d (32% oil and liquids and 68% natural gas) and included 16 gross (11.95 net) sections of Cardium and Mannville prospective lands in the Ferrier/Willesden Green Cardium resource play. The assets acquired also included a 25% working interest in an operated compressor station and gathering system. As a result of the acquisition, Bellatrix added an additional 25 net Cardium and 4 net Notikewin/Falher drilling locations to the Corporation's drilling inventory.

In late 2012, as a result of an ongoing joint venture development program with the O'Chiese First Nations, Bellatrix acquired an additional 11 gross and net sections of Cardium and Notikewin/Falher lands at Ferrier. This acquisition added an additional 37 net drilling locations in the Cardium, 9 net drilling locations in the Notikewin/Falher, and 66 net drilling locations in the Duvernay formation.

During the third quarter of 2012, Bellatrix closed on the disposition of a minor non-core property interest in the Wainwright area, Alberta for \$4.25 million after adjustments. This non-operated unit heavy oil property had production of approximately 59 BOE/d. The net proceeds from the disposition were initially used to reduce the Corporation's bank indebtedness, and ultimately were directed toward the development of the Corporation's Cardium oil resource program.

Bellatrix had other minor property dispositions in 2012 resulting in total cumulative property dispositions of \$6.7 million.

2013 Joint Ventures and Asset Acquisitions and Divestitures

Joint Venture with Grafton Energy Co I Ltd.

On June 27, 2013, Bellatrix closed a \$122 million joint venture (the "**Grafton Joint Venture**") with Grafton Energy Co I Ltd. ("**Grafton**"), to accelerate development on a portion of Bellatrix's extensive undeveloped land holdings. The Grafton Joint Venture is in Willesden Green and Brazeau areas of West-Central Alberta. Under the terms of the initial agreement, Grafton was to contribute 82%, or \$100 million, to the \$122 million Grafton Joint Venture to participate in an expected 29 Notikewin/Falher and Cardium well program.

On September 10, 2013, Grafton elected to exercise an option to increase the committed capital investment by an additional \$100 million on the same terms and conditions. Under the terms of the amended agreement, Grafton will contribute 82%, or \$200 million, to the \$244 million Grafton Joint Venture to participate in an expected 58 Notikewin/Falher and Cardium well program. Under the agreement, Grafton will earn 54% of Bellatrix's working interest in each well drilled in the well program until payout (being recovery of Grafton's capital investment plus an 8% return) on the total program, reverting to 33% of Bellatrix's working interest after payout. At any time after payout of the entire program, Grafton shall have the option to elect to convert all wells from the 33% working interest to a 17.5% gross overriding royalty on Bellatrix's pre-joint venture working interest. Grafton also has an additional one-time option within 12 months of the effective date to increase its exposure by an additional \$50 million on the same terms and conditions. The effective date of the agreement is July 1, 2013 and has a term of 2 years. If the \$50 million option is exercised, Bellatrix shall have until the end of the third anniversary of the effective date to spend the additional capital.

Asset Disposition and Strategic Partnership with Daewoo International Corporation and Devonian Natural Resources Private Equity Fund

On September 3, 2013, Bellatrix closed a \$200 million strategic joint venture (the "**Daewoo/Devonian Joint Venture**") and a \$52.5 million asset disposition with Daewoo International Corporation ("**Daewoo**") and Devonian Natural Resources Private Equity Fund ("**Devonian**"), whereby Bellatrix sold, effective July 1, 2013, to the Canadian subsidiaries of Daewoo and Devonian an aggregate 50% of the Corporation's working interest share of its producing assets, an operated compressor station and gathering system and related land acreage in the Baptiste area of West Central Alberta for gross consideration of \$52.5 million. The Daewoo/Devonian Joint Venture, which was effective as of July 1, 2013, encompasses a multiyear commitment to jointly develop the aforementioned acreage in Ferrier and Willesden Green of West Central Alberta encompassing 70 gross wells with anticipated total capital expenditures to the Daewoo/Devonian Joint Venture of approximately \$200 million.

Joint Venture with TCA Energy Ltd.

On November 11, 2013, Bellatrix closed a \$240 million joint venture partnership (the "**TCA Joint Venture**") with TCA Energy Ltd. ("**TCA**"). TCA is a Canadian incorporated special purpose vehicle for Troika Resources Private Equity Fund which is based in Seoul, Korea and managed by KDB Bank, SK Energy and Samchully AMC. Pursuant to the agreement forming the TCA Joint Venture, Bellatrix and TCA will drill and develop lands in the Ferrier Cardium area of West Central Alberta, with the program to be completed by December 31, 2014. TCA will contribute \$120 million, representing a 50% share, towards the capital program for the drilling of an expected 63 gross wells, and in exchange, will receive 35% of Bellatrix's working interest until payout (being recovery of TCA's capital investment plus a 15% internal rate of return) on the total program, and thereafter reverting to 25% of Bellatrix's working interest. As part of this agreement, TCA will be participating in 14 gross wells (as included in the total expected 63 gross well program) for wells that have been drilled since January 1, 2013, resulting in net proceeds of \$16.7 million that was received by Bellatrix at closing.

2013 Property Acquisition

During the fourth quarter of 2013, the Corporation increased its current working interest in certain Cardium and Notikewin/Falher lands and production in the Willesden Green (Baptiste) area of Alberta through the acquisition of additional working interests from several companies for a total combined net purchase price of \$10 million.

2013 Redemption of 4.75% Debentures

During the third quarter of 2013, Bellatrix issued a notice of redemption of its then outstanding \$55.0 million 4.75% Debentures, with a redemption date of October 21, 2013. During September 2013, \$5.021 million principal amount of 4.75% Debentures were converted into an aggregate of 895,605 Common Shares. Subsequent to September 30, 2013, the remaining \$49.979 million principal amount of 4.75% Debentures were converted or redeemed in exchange for an aggregate of 8,898,243 Common Shares.

2013 Public Offering of Common Shares

On November 5, 2013, Bellatrix closed a bought deal offering of 21,875,000 Common Shares at a price of \$8.00 per Common Share for aggregate gross proceeds of approximately \$175 million.

2013 Angle Arrangement

On December 11, 2013, Bellatrix and Angle closed the Angle Arrangement, pursuant to which, Bellatrix acquired all of the issued and outstanding Angle Shares and all of the issued and outstanding Angle Debentures. Pursuant to the Angle Arrangement, Bellatrix acquired all of the issued and outstanding Angle Shares for consideration consisting of \$69.7 million in cash and approximately 30.2 million Common Shares. Bellatrix acquired all of the issued and outstanding Angle Debentures in the aggregate principal amount of \$60 million on the basis of \$1,040 in cash per \$1,000 principal amount of the Angle Debentures, plus accrued and unpaid interest to December 10, 2013.

In conjunction with the Angle Arrangement, the Board of Directors of Bellatrix approved the appointment of Keith Turnbull, a former director of Angle, as a director of Bellatrix effective January 1, 2014.

As part of the Angle Arrangement, Angle and its subsidiary, Angle Resources Inc., were amalgamated with Bellatrix and continued under the name "Bellatrix Exploration Ltd." and the Angle Shares were delisted from the TSX.

2013 Increased Credit Facilities

Upon completion of the Angle Arrangement, Bellatrix entered into credit facilities with an increased borrowing base of \$500 million (subject to the semi-annual borrowing base test on May 31 and November 30 each year), available on an extendible revolving term basis. For additional information relating to the credit facilities, see "*Borrowings*".

Significant Acquisitions

On December 11, 2013, Bellatrix acquired all of the issued and outstanding Angle Shares and all of the issued and outstanding Angle Debentures, pursuant to the Angle Arrangement. Under the Angle Arrangement, Bellatrix acquired all of the issued and outstanding Angle Shares for consideration consisting of \$69.7 million in cash and approximately 30.2 million Common Shares. Bellatrix also acquired all of the issued and outstanding Angle Debentures in the aggregate principal amount of \$60 million on the basis of \$1,040 in cash per \$1,000 principal amount of the Angle Debentures, plus accrued and unpaid interest to December 10, 2013.

Bellatrix has filed a Form 51-102F4 – *Business Acquisition Report* in connection with the above noted acquisition, which is available on SEDAR at www.sedar.com.

Other than the Angle Arrangement, the Corporation has not completed any acquisitions that would be considered significant pursuant to NI 51-102 since January 1, 2013.

DESCRIPTION OF BUSINESS

Business Plan and Growth Strategies

Bellatrix is a Western Canadian based growth oriented oil and gas company engaged in the exploration for, and the acquisition, development and production of oil and natural gas reserves in the provinces of Alberta, British Columbia and Saskatchewan. The business plan of Bellatrix is to create sustainable and profitable per share growth in reserves, production and cash flow in the oil and gas industry. To accomplish this, Bellatrix pursued an integrated growth strategy with active development and exploration drilling within its core areas, together with focused acquisitions and strategic joint ventures. Bellatrix will continue to target areas and prospects that it believes could result in meaningful reserve and production additions.

Bellatrix will continue to pursue internal and external generation of exploration plays that have low to medium risk and multi-zone potential. Bellatrix intends to maintain a balance between exploration, exploitation and development drilling targeting both oil and natural gas reserves over the course of the next several years. Bellatrix considers asset and corporate acquisition opportunities from time to time that meet Bellatrix's business parameters.

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

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

In general, Bellatrix is expected to continue to pursue a portfolio approach in developing a large number of opportunities with a balance of risk profiles and commodity exposure in an attempt to generate high levels of sustainable growth.

With Bellatrix's improved financial flexibility, management plans to seek opportunities to consolidate assets that complement its focused asset base either through geographic fit, technical expertise or future development potential.

Bellatrix may, in its discretion, proceed with asset or corporate acquisitions 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, Bellatrix may from time to time consider seeking joint venture partners, strategic investors or other business arrangements to help accelerate development of its properties.

Bellatrix's management team is comprised of a proven team of professional management 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*".

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Bellatrix competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Bellatrix's competitors include resource companies which have greater financial resources, staff and facilities than those of Bellatrix. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Bellatrix 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.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 4, 2014. The effective date of the Statement is December 31, 2013 and the preparation date of the Statement is March 4, 2014.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by Sproule with an effective date of December 31, 2013. The Reserves Data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Data conforms with the requirements of NI 51-101. We engaged Sproule to provide an evaluation of proved and proved plus probable reserves. No attempt was made to evaluate possible reserves. All of our reserves are in Canada in the provinces of Alberta, British Columbia and Saskatchewan. Field inspections were not conducted.

The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by our independent qualified reserves evaluators in Form 51-101F2 are attached as Schedule "A" and Schedule "B" respectively, hereto.

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

Reserves Data (Forecast Prices and Costs)

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS**

Reserves Category	Light And Medium Oil		Heavy Oil		Natural Gas ⁽¹⁾		Natural Gas Liquids	
	Gross (Mbbbls)	Net (Mbbbls)	Gross (Mbbbls)	Net (Mbbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbls)	Net (Mbbbls)
Proved Developed Producing	9,396.2	7,352.2	104.0	74.3	195,675	153,738	11,924.1	7,962.3
Proved Developed Non-Producing	115.6	104.1	-	-	3,121	2,654	143.7	91.2
Proved Undeveloped	9,481.3	7,679.3	112.8	84.1	275,557	227,456	13,774.2	9,763.4
Total Proved	18,993.1	15,135.7	216.8	158.4	474,353	383,848	25,841.9	17,816.9
Probable	11,568.1	9,120.4	264.9	193.9	326,065	265,000	21,194.8	14,569.1
Total Proved Plus Probable	30,561.2	24,256.1	481.7	352.3	800,418	648,848	47,036.7	32,386.0

Note:

- (1) Includes minor amounts of natural gas from coal bed methane and shale gas reserves.

Net Present Values of Future Net Revenue

Reserves Category	Before Income Taxes Discounted At (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10% Year ⁽¹⁾	
	0	5	10	15	20	0	5	10	15	20	(\$/BOE)	(\$/Mcf)
	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)	(\$000s)		
Proved Developed Producing	1,401,678	1,070,782	879,300	754,390	666,223	1,350,899	1,049,269	869,286	749,391	663,586	21.44	128.64
Proved Developed Non-Producing	16,906	13,841	11,760	10,263	9,136	12,679	11,447	10,365	9,429	8,626	18.44	110.64
Proved Undeveloped	1,283,180	808,145	542,023	376,274	265,409	962,372	599,581	395,454	267,800	182,110	9.78	58.68
Total Proved	2,701,764	1,892,768	1,433,082	1,140,927	940,768	2,325,950	1,660,297	1,275,105	1,026,620	854,322	14.76	88.56
Probable	2,166,291	1,115,405	656,989	417,871	277,356	1,624,559	825,100	474,421	290,892	182,971	9.65	57.90
Total Proved Plus Probable	4,868,056	3,008,173	2,090,071	1,588,798	1,218,125	3,950,509	2,485,397	1,749,526	1,317,513	1,037,293	12.66	75.96

Note:

- (1) Unit values are based upon net reserves.

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS**

Reserves Category	Revenue (\$000s)	Royalties (\$000s)	Operating Costs (\$000s)	Capital Development Costs (\$000s)	Abandonment Costs (\$000s)	Future Net Revenue Before Income Taxes (\$000s)	Income Tax (\$000s)	Future Net Revenue After Income Taxes (\$000s)
Proved Reserves	6,371,178	1,356,561	1,490,885	786,977	34,990	2,701,764	375,814	2,325,950
Proved Plus Probable	11,386,448	2,471,199	2,713,712	1,284,616	48,866	4,868,056	917,547	3,950,509

**FUTURE NET REVENUE
BY PRODUCTION GROUP⁽¹⁾
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS**

<u>Reserves Category</u>	<u>Production Group⁽¹⁾</u>	<u>Future Net Revenue Before Income Taxes (discounted at 10%/year) (\$000s)</u>	<u>Unit Value⁽²⁾ Before Income Tax (discounted at 10%/year)</u>
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	628,849	\$18.35/BOE
	Heavy Oil (including solution gas and other by-products)	4,653	\$29.38/BOE
	Natural Gas (including by-products but excluding solution gas from oil wells) ⁽³⁾	781,007	\$12.46/BOE
	Other ⁽⁴⁾	18,574	
	Total	<u>1,433,082</u>	
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	895,349	\$15.46/BOE
	Heavy Oil (including solution gas and other by-products)	9,657	\$27.41/BOE
	Natural Gas (including by-products but excluding solution gas from oil wells) ⁽³⁾	1,161,987	\$10.87/BOE
	Other ⁽⁴⁾	23,078	
	Total	<u>2,090,071</u>	

Notes:

- (1) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups.
- (2) Unit values are based on net reserves.
- (3) Includes minor amounts of revenue and costs associated with natural gas from coal bed methane and shale gas reserves.
- (4) Other includes revenue from processing plants, third party processing and other non-commodity sales sources.

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.
2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Sproule Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

Reserve Categories

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

- Analysis of drilling, geological, geophysical and engineering data;
- The use of established technology; and
- Specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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

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

- (b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

- (a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
- (i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
- (ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

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

- (a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

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

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

3. Well abandonment and disconnect costs were estimated and included in the Sproule report at the individual entity level for all wells that were assigned reserves. No allowance for surface lease reclamation and salvage value was included. No abandonment costs have been estimated for suspended wells, gathering systems, batteries, plants or processing facilities.
4. The after-tax net present value of the Corporation's properties here reflects the tax burden on all of the properties of the Corporation taken as a whole. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion and analysis of the Corporation should be consulted for information at the level of the business entity. Furthermore, the tax methodology used assumes that all tax pools are utilized to the maximum depreciation rate as currently permitted.
5. Forecast Prices and Costs

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the Sproule Report were an average of forecast prices and costs published by Sproule, GLJ Petroleum Consultants Ltd., and McDaniel & Associates Consultants Ltd. as at January 1, 2014, which are as follows:

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS**

Year	OIL			NATURAL GAS AECO Price (\$Cdn/MMBtu)	NATURAL GAS LIQUIDS at Edmonton ⁽¹⁾ (\$Cdn/Bbl)	INFLATION RATES ⁽²⁾ %/Year	EXCHANGE RATE ⁽³⁾ (\$US/\$Cdn)
	Edmonton Par Price 40° API (\$Cdn/Bbl)	Western Canada Select 20.5° API (\$Cdn/Bbl)	Cromer LSB 35° API (\$Cdn/Bbl)				
Forecast							
2014	93.47	76.64	90.77	4.01	103.73	1.833	0.947
2015	94.39	77.99	91.37	4.17	102.83	1.833	0.947
2016	95.71	79.06	92.82	4.35	102.58	1.833	0.947
2017	99.87	82.59	98.81	4.81	107.24	1.833	0.947
2018	100.48	83.08	99.57	4.99	107.91	1.833	0.947
2019	101.43	83.88	100.35	5.18	108.96	1.833	0.947
2020	102.88	85.06	101.51	5.29	110.51	1.833	0.947
2021	104.75	86.62	103.29	5.38	112.49	1.833	0.947
2022	106.67	88.20	105.10	5.48	114.56	1.833	0.947
2023	108.65	89.83	106.95	5.58	116.68	1.833	0.947
Thereafter	+1.833%/yr	+1.833%/yr	+1.833%/yr	+1.833%/yr	+1.833%/yr		

Notes:

- (1) Natural gas liquids is represented by pentanes plus price.
- (2) Inflation rates for forecasting prices and costs.
- (3) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by Bellatrix (before commodity price risk management contracts) for the year ended December 31, 2013, were \$3.49/Mcf for natural gas, \$92.66/Bbl for light and medium gravity crude oil and condensate, \$68.41/Bbl for heavy oil and \$43.85/Bbl for natural gas liquids (excluding condensate).

Reconciliation of Changes in Reserves

The following table sets out the reconciliation of our gross reserves as at December 31, 2012 compared to December 31, 2013 based on forecast prices and costs by principal product type:

FACTORS	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2012⁽²⁾	10,468.0	6,057.9	16,525.9	181.0	224.2	405.2
Discoveries	-	-	-	-	-	-
Extensions	2,022.1	2,762.5	4,784.6	-	-	-
Infill Drilling	310.3	134.7	445.0	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(198.3)	(1,181.8)	(1,380.1)	106.4	36.2	142.6
Acquisitions	7,625.1	4,042.8	11,667.9	-	-	-
Dispositions	(186.1)	(349.6)	(535.7)	-	-	-
Economic Factors	(104.3)	101.6	(2.7)	(0.1)	4.5	4.4
Production	(943.7)	-	(943.7)	(70.5)	-	(70.5)
December 31, 2013⁽³⁾	18,993.1	11,568.1	30,561.2	216.8	264.9	481.7

FACTORS	NATURAL GAS LIQUIDS			NATURAL GAS ⁽¹⁾		
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
December 31, 2012⁽²⁾	9,008.1	8,576.3	17,584.4	213,348	201,962	415,310
Discoveries	-	-	-	-	-	-
Extensions	6,154.3	5,342.2	11,496.5	151,016	122,132	273,147
Infill Drilling	272.2	368.1	640.3	3,012	2,261	5,273
Improved Recovery	-	-	-	-	-	-
Technical Revisions	1,679.9	(3,076.2)	(1,396.3)	56,769	(65,265)	(8,496)
Acquisitions	10,205.0	10,671.0	20,876.0	89,088	80,379	169,468
Dispositions	(117.0)	(666.0)	(783.0)	(4,416)	(14,558)	(18,974)
Economic Factors	(7.5)	(20.6)	(28.1)	(900)	(846)	(1,746)
Production	(1,353.1)	-	(1,353.1)	(33,563)	-	(33,563)
December 31, 2013⁽³⁾	25,841.9	21,194.8	47,036.7	474,353	326,065	800,418

Notes:

- (1) Includes minor amounts of natural gas from coal bed methane and shale gas reserves.
- (2) As evaluated by Sproule in a report dated March 5, 2013 and effective as of December 31, 2012.
- (3) As evaluated in the Sproule Report.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped gross reserves and the probable undeveloped gross reserves, each by product type, attributed to Bellatrix's assets for the years ended December 31, 2013, 2012 and 2011 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbbl)		Heavy Oil (Mbbbl)		Natural Gas ⁽¹⁾ (MMcf)		NGLs (Mbbbl)	
	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End
Prior thereto	3,742	3,742	60	60	28,090	28,090	961	961
2011	2,552	4,425	30	210	49,804	84,812	1,919	3,250
2012	1,124	5,119	-	113	36,227	120,898	1,496	5,200
2013	1,430	9,481	-	113	123,060	275,557	5,186	13,774

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbbl)		Heavy Oil (Mbbbl)		Natural Gas ⁽¹⁾ (MMcf)		NGLs (Mbbbl)	
	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End
Prior thereto	4,191	4,191	90	90	34,218	34,218	1,167	1,167
2011	2,924	3,458	5	120	46,531	65,527	1,843	2,655
2012	1,620	3,859	-	200	81,223	163,856	4,922	7,003
2013	2,594	8,328	-	199	116,455	259,669	5,386	17,252

Note:

- (1) Includes minor amount of natural gas from coal bed methane and shale gas reserves.

Proved Undeveloped Reserves

A total of 275,557 MMcf of natural gas, 9,594 Mbbbl of oil and 13,744 Mbbbl of NGLs were assigned as proved undeveloped reserves as at December 31, 2013, representing approximately 56% of our total proved reserves. In estimating future net revenue Sproule reviewed Bellatrix's future development plans in order to estimate and deduct future development costs. Therefore the future development costs as set under "*Future Development Costs*" are consistent with Bellatrix's future development plans at year end. The proved undeveloped reserves are generally associated with infill/development drilling locations supported by offset well data. The largest portion of the capital associated with developing proved undeveloped reserves is expected to be spent between 2014 and 2017. With respect to capital development costs associated with proved undeveloped reserves in the Sproule Report, approximately 62% of the capital is scheduled to be spent over the next two years and 87% is scheduled to be spent over the next three years.

The West Central region of Alberta is a significant producing and development area for Bellatrix. Development drilling in both the proved and probable cases is anticipated for oil and gas in Pembina, Baptiste, Brazeau and Ferrier and represents 63.5% of all assigned proven future development capital. The programs are staged in line with sound development practices and to exploit horizontal drilling and multi-fracturing completion opportunities.

Residual future development capital is assigned across various other properties operated by Bellatrix including Willesden Green and Frog Lake. The majority of this spending is also forecast for the next three years with minor work planned past this point, based on relief of existing wellbore constraints.

Although Bellatrix expects the development of its proved undeveloped reserves to be consistent with that set out above, current industry conditions and other uncertainties as indicated under "*Risk Factors*" herein could result in development of Bellatrix's proved undeveloped reserves on a different schedule than set out above.

Probable Undeveloped Reserves

A total of 259,669 MMcf of natural gas, 8,526 Mbbbl of oil and 17,252 Mbbbl of NGLs were assigned as gross probable undeveloped reserves in 2013, representing approximately 79% of our total probable reserves or 33% of total proved plus probable reserves.

The bulk of the probable undeveloped reserves assigned are associated with projects that have a proved reserves component. Probable reserves are attributed in addition to proved reserves in these cases according to the definitions and guidelines of the COGE Handbook. There are also some projects assigned probable reserves that do not have a proven reserves component, as per the terms of the COGE Handbook.

As was the case with proved undeveloped reserves, the West Central Alberta region has significant probable undeveloped reserves. The expenditures required to develop the probable undeveloped reserves are scheduled in a staggered pattern from 2014 to 2017. With respect to capital development costs associated with probable undeveloped reserves in the Sproule Report, approximately 54% of the capital is scheduled to be spent over the next two years and 86% is scheduled to be spent over the next three years. In scheduling future development capital, priority is given to projects with a proved component, as those projects have reduced risk and are easier to predict timing or serve to prove up further projects currently only assigned probable reserves.

Although Bellatrix expects the development of its probable undeveloped reserves to be consistent with that set out above, current industry conditions and other uncertainties as indicated under "*Risk Factors*" herein could result in development of Bellatrix's probable undeveloped reserves on a different schedule than set out above.

Significant Factors or Uncertainties

While we do not anticipate any significant economic factors or uncertainties will affect any particular components of the reserves data, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control (see "*Risk Factors*").

Future Development Costs

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

<u>Year</u>	<u>Proved Reserves (\$000s)</u>	<u>Proved Plus Probable Reserves (\$000s)</u>
2014	265,755	411,531
2015	219,343	343,299
2016	198,868	356,991
2017	102,245	172,028
2018	-	-
Thereafter	767	767
Total: Undiscounted	<u>786,977</u>	<u>1,284,616</u>

The capital expenditure program developed for the reserves evaluation, including estimated future development costs, was developed based on using cash flow from operations and available credit facilities. Equity financing was also considered to fund operations. If cash flows are other than projected, capital expenditure levels will be adjusted. Our practice of continually monitoring spending opportunities in comparison to expected cash flow levels allows for adjustments to the capital program as required.

The expected costs of funding our capital expenditures have been built into the economics of the programs and the reserves evaluation.

Other Oil and Gas Information

Principal Properties

The following is a description of Bellatrix's principal oil and natural gas properties as at December 31, 2013. Unless otherwise indicated, production stated is average daily production for the year ended December 31, 2013 received by Bellatrix in respect of its working interest share before deduction of royalties and without including any royalty interest.

The principal properties include two recent additions to the Bellatrix group of key properties. The Strachan and Harmattan assets were acquired pursuant to the Angle Arrangement in late 2013. Both areas include resource development potential in the Cretaceous Cardium and Mannville units for both light oil and liquids rich natural gas. As a result of the acquisition of these properties Bellatrix's current focus area on Cretaceous resource plays now extends from West Pembina to Harmattan.

Ferrier

Located 35 kilometres northwest of Rocky Mountain House, Alberta, the Ferrier and Alder Flats areas produce natural gas and natural gas liquids from the Belly River, Cardium Notikewin, Falher and Rock Creek zones at depths ranging from 1,800 to 2,700 metres. Area production averaged 16,849 BOE/d in 2013, comprised of 75% natural gas, 13% natural gas liquids and 12% light oil and condensate. The majority of oil production from the area is sent to three compressor stations and one battery which Bellatrix has a 100% working interest. Gas volumes from the area are sent to third party non-operated gas plants for processing, including two major gas processing facilities in the area in which Bellatrix holds a minor working interest. Bellatrix's land holdings in the area were 45,723 gross (26,045 net) acres of developed land and 46,893 gross (40,509 net) acres of undeveloped land as at December 31, 2013.

The Corporation operated the drilling and tie-in of 32 gross (28.6 net) Cardium oil and liquids-rich horizontal gas wells at Ferrier in 2013. Bellatrix also participated in 2.0 gross (0.67 net) non-operated Cardium oil wells. All 34 (29.3 net) Cardium wells drilled or participated in by Bellatrix in the area in 2013 were successful. Although historically Bellatrix has experienced the best performance from Cardium wells when completions were conducted with the slick water technique, the Corporation continues to consider some of the newer advances in completion techniques and in 2014 plans to test the application of the scissor style completion technique in a number of upcoming Cardium wells to determine whether there is any improvement in production performance.

In 2013 Bellatrix drilled a total of 17 gross (9.7 net) Notikewin-Falher liquids rich gas wells at Ferrier with 100% success which were completed tied and placed on production. In addition, the Corporation participated in one (0.5 net) non-operated successful Notikewin-Falher gas well in 2013.

To date in 2014 at Ferrier, the Corporation has drilled or is currently drilling a total of 15 gross (9.1 net) Cardium horizontal wells, which are in various stages of completion and tie-in. The Corporation has also drilled 4 gross (1.0 net) Notikewin-Falher horizontal wells, of which 1 gross (0.2 net) well has been completed, tied in and placed on production and the three remaining wells are on schedule to be completed in early March.

Although Bellatrix continues to monitor the emerging Duvernay resource play at Ferrier, it did not drill any Duvernay wells in 2013. The Corporation has successfully increased its land holdings in the Duvernay liquids rich gas fairway with current Duvernay prospective land holdings of 200 gross (186 net) sections.

Willesden Green

The Willesden Green area is located approximately 45 kilometres north of Rocky Mountain House, Alberta. This property produces oil and associated natural gas from the Cardium zone, liquids-rich natural gas from zones in the Notikewin, Falher, Ellerslie, and Rock Creek formations at depths of 1,800 to 2,800 metres, and sweet dry natural gas from five shallower horizons, including the Paskapoo, Ardley, Horseshoe Canyon, Edmonton and Belly River at depths of 300 to 1,200 metres. Production from this area in 2013 averaged 1,609 BOE/d, consisting of 62% natural gas, 23% light oil and 15% natural gas liquids. The majority of this production is operated by Bellatrix. The Corporation owns and operates three compressor stations in the area. Gas is sent to a Bellatrix owned third party operated gas plant for processing. Bellatrix held 32,800 gross (16,724 net) acres of developed land and 11,040 gross (5,075 net) acres of undeveloped land in the area as at December 31, 2013.

Bellatrix drilled or participated in a total of 18 gross (8.7 net) successful oil and liquids rich gas wells in the Cardium and Notikewin-Falher zones at Willesden Green and Baptiste in 2013. The Corporation operated the drilling, completion and tie-in of 14 gross (7.3 net) Cardium horizontal oil and liquids rich gas wells in 2013 and also participated in 4 gross (1.1 net) successful non-operated Cardium horizontal wells. In addition to the Cardium and Notikewin-Falher wells, the Corporation drilled 1.0 gross (0.3 net) Upper Mannville liquids-rich gas discovery well at Baptiste in 2013 which has been tied in.

To date in 2014, the Corporation has drilled and completed 10 gross (4.0 net) Cardium horizontal wells at Willesden Green and are in the process of drilling 1 gross (0.25 net) Upper Mannville horizontal well (0.25 net).

Greater Pembina

Pembina is located about 25 kilometres west of Drayton Valley, Alberta. Significant oil reserves occur in the Cardium zone at a depth of 1,800 metres and, in addition, there is liquids-rich natural gas potential in the Mannville and Jurassic zones at depths of approximately 2,150 to 2,500 metres. In 2013, area production averaged 1,588 BOE/d, consisting of 25% natural gas, 69% light oil and condensate, and 6% natural gas liquids. Oil production from the area is sent to Bellatrix owned and operated oil batteries and gas production is sent to a third party non-operated gas plant for processing. Bellatrix held 51,389 gross (28,876 net) acres of developed land and 14,252 gross (6,813 net) acres of undeveloped land in this area as at December 31, 2013. Bellatrix had 100% success in its drilling programs in Greater Pembina in 2013. The Corporation drilled and tied-in 7 (6.5 net) gross Cardium horizontal wells. All of the wells were completed, tied-in and placed on production.

To date in 2014, the Corporation has drilled a total of 5 gross (4.8 net) Cardium horizontal wells in the Greater Pembina area, which are in various stages of completion and tie-in. In addition, in 2014 Bellatrix has drilled 1 gross (0.5 net) successful horizontal well into the Lower Mannville Ellerslie formation, which is currently being tied in.

Strachan

Strachan is located approximately 12 kilometres south of Rocky Mountain House, Alberta. Bellatrix acquired the Strachan property pursuant to the Angle Arrangement in December 2013. The area aligns well with Bellatrix's focus on the light oil and liquids rich natural gas fairway in the Alberta Deep Basin. Historically, the area had been the focus of vertical drilling for oil and gas resources in the Cretaceous units; however, the area has experienced a rejuvenation of development activity with the onset of horizontal well development.

The Strachan property produces oil, natural gas and associated natural gas liquids from the Cardium formation from depths of 2,000 and 2,700 meters. Production from the property for the twelve months ended December 31, 2013 averaged 3,461 BOE/d, comprised of 14% oil, 61% natural gas, and 25% natural gas liquids. As the Angle Arrangement closed on December 11, 2013, Bellatrix has only recorded production of 253 BOE/d from this property for the 21 days it owned the property. The Corporation owns and operates four facilities and has a 100% working interest in two compressor stations and has a 64.75% working interest and 50.25% working interest in two other compressor stations. All gas production volumes are sent on to a third party non-operated gas plant for processing. Bellatrix is planning construction of a 100% owned oil battery where all emulsion will be processed and a new compressor station which will handle any expansion in gas volumes. Bellatrix held 20,323 gross (14,191 net) acres of developed land and 53,839 gross (46,327 net) acres of undeveloped land in this area as at December 31, 2013.

In 2013, Angle drilled or participated in a total of 10 gross (7.8 net) Cardium horizontal wells with encouraging results. The oil and liquids rich natural gas discovered in the area are very similar to the Cardium producing properties that Bellatrix has developed at Ferrier and Willesden Green.

To date in 2014, Bellatrix has initiated a 10 gross (10.0 net) well horizontal drilling program, which includes 6 gross (6.0 net) Cardium horizontal wells in the first half of 2014. Bellatrix drilled its first Cardium oil well at Strachan in February 2014 and the well has been completed and placed on production. The Corporation is currently in the process of drilling its second Cardium oil well.

Harmattan

Harmattan is located approximately 80 kilometres northwest of Calgary near the town of Sundre, Alberta. Bellatrix acquired the Harmattan property pursuant to the Angle Arrangement in December 2013. This property produces oil and associated natural gas from the Cardium and Viking zones and liquids-rich natural gas from zones in the Lower Mannville and Rock Creek formations at depths of 1,200 to 2,600 metres. Production from the property for the twelve months ended December 31, 2013 averaged 7,307 BOE/d, consisting of 36% natural gas, 32% light oil and 32% natural gas liquids. As the Angle Arrangement closed on December 11, 2013, Bellatrix has only recorded production of 364 BOE/d from this property for the 21 days it owned the property. The majority of the production from the area is operated by Bellatrix. The Corporation owns a 100% working interest in a large oil battery and a compressor station

where a majority of oil volumes are handled. All gas is sent to a third party non-operated gas plant for processing. Bellatrix held 36,414 gross (33,912 net) acres of developed land and 71,764 gross (69,062 net) acres of undeveloped land in this area as at December 31, 2013.

In 2013, Angle drilled or participated in 18 gross (17.3 net) horizontal wells that were drilled into the continuous marine sandstones of the Cardium formation at Harmattan. Although the project showed moderate success, it was considered to be only marginally economic in comparison to Bellatrix's northern Cardium projects. Management of the Corporation believes that there may be potential to improve rates of return if the Corporation is able to reduce capital costs and increase production performance of the Cardium zone in the area.

In addition, Angle drilled a total of 6 gross (6.0 net) horizontal Lower Mannville wells at Harmattan in 2013 of which 5 gross (5.0 net) have been completed and placed on production.

Management believes that current mapping supports very good potential for resource development of the oil and liquids rich gas reserves in the Lower Mannville and, although management considers the results of drilling in the Lower Mannville at Harmattan and Davey Lake to be encouraging, they believe there is potential to improve netbacks from this play.

Bellatrix intends to conduct a re-evaluation of the multi-zone potential at Harmattan for oil and liquids rich natural gas and expects to formulate a drilling plan for the second half of 2014.

Oil and Natural Gas Wells

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

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	366	220	81	31	845	485	128	79
Saskatchewan	2	1	0	0	27	27	29	28
British Columbia	0	0	2	1	7	2	7	2
Total	368	221	83	32	879	513	164	109

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2013.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	443,780	272,114	436,436	360,821	880,216	632,935
British Columbia	9,752	2,692	107,700	47,521	117,452	50,213
Saskatchewan	13,327	12,720	8,289	8,289	21,616	21,009
Total	466,859	287,526	552,425	416,631	1,019,284	704,157

Note:

(1) May not add due to rounding.

The following provides details of certain of the Corporation's drilling commitments as at December 31, 2013:

- Bellatrix committed to drill 10 gross (5.7 net) wells pursuant to farm-in agreements as at December 31, 2013. Bellatrix expects to satisfy these drilling commitments at an estimated net cost of approximately \$20.0 million.
- Pursuant to a joint venture agreement dated February 1, 2011, Bellatrix is committed to drilling 3 gross (3.0 net) wells per year between 2011 and 2015 for a total estimated cost of approximately \$52.5 million. As at December 31, 2013, 6 wells remained to be drilled under this commitment for a total estimated cost of \$21.0 million.
- Pursuant to a joint venture agreement dated August 4, 2011, Bellatrix is committed to drilling 5 to 10 gross and net wells per year between 2011 and 2016 for a total of 40 gross and net wells at an estimated cost of approximately \$140.0 million. As at December 31, 2013, 12 wells remained to be drilled under this commitment for a total estimated cost of \$42.0 million.
- Pursuant to a joint venture agreement dated December 14, 2012, Bellatrix is committed to drilling 2 gross and net wells per year between 2014 and 2018 for a total of 10 gross and net wells at an estimated cost of approximately \$35.0 million. As at December 31, 2013, 7 wells remained to be drilled under this commitment for a total estimated cost of \$24.5 million.

Potentially, approximately 3.25% of our mineral rights could expire by December 31, 2014 as a result of those rights reaching maximum land tenure. Bellatrix plans to evaluate and identify potential drilling operations on selected portions of these lands, to be tested prior to expiry to preserve the rights, and/or to submit applications to continue that acreage.

In addition to the above noted drilling commitments the Corporation entered into a number of joint venture agreements in 2013 as described under the heading *General Developments of the Business – 2013 Joint Ventures and Asset Acquisitions and Divestitures*.

Development of Bellatrix properties with no attributable reserves are subject to current industry conditions and uncertainties as indicated under "Risk Factors" herein. In addition, we expect that funding of development operations on such properties will be evaluated in the context of our total capital requirements having regard to rates of return, the likelihood of success and risked return versus cost of capital, and availability and reliability of methods of hydrocarbon delivery.

Forward Contracts and Marketing

Our commodity marketing strategy is to sell production in the spot market, complemented from time to time by price risk management instruments.

We periodically hedge the price on a portion of our crude oil and natural gas production. We hedged an average of 56% of total crude oil and natural gas liquids production and an average of 36% of total natural gas production during the twelve months ended December 31, 2013. The following provides details of the commodity price risk management arrangements outstanding as at December 31, 2013 and as of the date hereof.

As at December 31, 2013, the Corporation had entered into commodity price risk management arrangements as follows:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Crude oil fixed	January 1, 2014 to Dec. 31, 2014	500 bbl/d	\$ 93.30 US	\$ 93.30 US	WTI
Crude oil fixed	January 1, 2014 to Dec. 31, 2014	1,500 bbl/d	\$ 94.00 CDN	\$ 94.00 CDN	WTI
Crude oil fixed	January 1, 2014 to Dec. 31, 2014	500 bbl/d	\$ 95.00 US	\$ 95.00 US	WTI
Crude oil fixed	January 1, 2014 to Dec. 31, 2014	1,500 bbl/d	\$ 95.22 CDN	\$ 95.22 CDN	WTI
Crude oil fixed	January 1, 2014 to Dec. 31, 2014	500 bbl/d	\$ 98.30 CDN	\$ 98.30 CDN	WTI
Crude oil fixed	January 1, 2014 to Dec. 31, 2014	1,000 bbl/d	\$ 99.50 CDN	\$ 99.50 CDN	WTI
Crude oil fixed	January 1, 2014 to Dec. 31, 2014	500 bbl/d	\$ 99.60 CDN	\$ 99.60 CDN	WTI

Crude oil call option ⁽¹⁾	January 1, 2014 to Dec. 31, 2014	1,500 bbl/d	-	\$ 105.00 US	WTI
Natural gas fixed	January 1, 2014 to June 30, 2014	15,000 GJ/d	\$ 3.05 CDN	\$ 3.05 CDN	AECO
Natural gas fixed	January 1, 2014 to Dec. 31, 2014	20,000 GJ/d	\$ 3.30 CDN	\$ 3.30 CDN	AECO
Natural gas fixed	January 1, 2014 to Dec. 31, 2014	20,000 GJ/d	\$ 3.60 CDN	\$ 3.60 CDN	AECO
Natural gas fixed	July 1, 2014 to Dec. 31, 2014	15,000 GJ/d	\$ 3.71 CDN	\$ 3.71 CDN	AECO

Note:

- (1) Subsequent to December 31, 2013, the Corporation settled the crude oil call options for the term of February to December 31, 2014 for US \$0.5 million.

Subsequent to December 31, 2013, the Corporation has entered into commodity price risk management arrangements as follows:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Natural gas fixed	February 1, 2014 to Dec. 31, 2014	10,000 GJ/d	\$ 3.79 CDN	\$ 3.79 CDN	AECO
Natural gas fixed	February 1, 2014 to Dec. 31, 2014	10,000 GJ/d	\$ 3.80 CDN	\$ 3.80 CDN	AECO
Natural gas fixed	February 1, 2014 to Dec. 31, 2014	15,000 GJ/d	\$ 3.85 CDN	\$ 3.85 CDN	AECO
Natural gas fixed	February 1, 2014 to Dec. 31, 2014	10,000 GJ/d	\$ 3.84 CDN	\$ 3.84 CDN	AECO
Natural gas fixed	February 1, 2014 to February 28, 2014	10,000 GJ/d	\$ 4.66 CDN	\$ 4.66 CDN	AECO
Natural gas fixed	March 1, 2014 to Dec. 31, 2014	10,000 GJ/d	\$ 4.14 CDN	\$ 4.14 CDN	AECO

Additional Information Concerning Abandonment and Reclamation Costs

We have included the estimated future well abandonment costs for existing and future reserves wells in the economic forecasts. We use our historical cost information on an area by area basis as the means for estimating the future abandonment costs. When this information is not available, the estimate is determined with reference to appropriate regulatory standards and requirements. Additional abandonment and reclamation costs associated with non-reserves wells, reclamation costs for wells with reserves and facility abandonment and reclamation expenses have not been included in the reserve report analysis.

In the Sproule Report, the number of existing and future net oil and gas wells for which revenues and costs are forecast, including future well abandonment costs, varies by year depending on when wells commence and end production. The total amount of such costs, all of which is deducted in the calculation of future net revenue from proved and proved plus probable reserves report is \$35.0 million (\$8.9 million discounted at 10%) and \$48.9 million (\$7.2 million discounted at 10%), respectively. In the next three financial years, these costs are as follows:

Year	Total Proved (\$000's)	Total Proved Plus Probable (\$000's)
2014	639	529
2015	709	372
2016	881	709
Subtotal	2,229	1,610
Remainder	32,761	47,256
Total (Undiscounted)	34,990	48,866
Total discounted at 10%	8,894	7,174

We currently have 1,151 net wells for which we expect to incur abandonment and reclamation costs. This includes some wells which have not been included in Sproule's calculation of abandonment costs where no reserves are attributable. At December 31, 2013, the estimated total undiscounted amount required to settle the asset retirement obligations (being abandonment and reclamation costs for net producing and shut in wells and facilities) of the Corporation was approximately \$122.7 million, of which \$67.1 million has been recorded. The incremental costs for future site restoration for surface leases and pipelines, reduced by the estimated salvage values for all included wells and facilities, is estimated to be nominal.

Tax Horizon

The Corporation does not expect to pay current income tax for the 2013 fiscal year. Depending on production, commodity prices and capital spending levels, management believes that the Corporation will not be taxable in 2014. The Corporation does not expect to pay current taxes until 2015 or beyond.

Capital Expenditures

The following table summarizes capital expenditures (excludes non-cash expenditures relating to decommissioning liabilities, capitalized unit based compensation and corporate acquisitions) related to our assets and activities for the year ended December 31, 2013:

	\$000's
Property acquisition costs	
Proved properties	13,380
Undeveloped properties	11,190
Exploration costs	140
Development costs	269,679
Dispositions	(70,936)
Corporate Assets	9,270
Total	<u>232,723</u>

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Bellatrix has an interest that were drilled during the year ended December 31, 2013.

	<u>Exploratory Wells</u>		<u>Development Wells</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Light and Medium Oil	3	2.65	54	38.58
Natural Gas	1	1.00	22	10.61
Heavy Oil	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	<u>4</u>	<u>3.65</u>	<u>76</u>	<u>49.19</u>

For details on the important current and likely exploration and development activities during 2013, see "Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties".

Production Estimates

The following table sets out the volume of our gross production estimated for the year ended December 31, 2014, which is reflected in the estimate of gross proved reserves and gross proved plus probable reserves disclosed in the tables contained under "Disclosure of Reserves Data" above.

<u>Reserves Category</u>	<u>Light And Medium Oil (Bbls/d)</u>	<u>Heavy Oil (Bbls/d)</u>	<u>Natural Gas⁽¹⁾ (Mcf/d)</u>	<u>Natural Gas Liquids (Bbls/d)</u>	<u>Total (BOE/d)</u>
Total Proved	5,582	136	143,484	7,765	37,397
Total Proved Plus Probable	<u>6,191</u>	<u>140</u>	<u>163,464</u>	<u>8,913</u>	<u>42,488</u>

Note:

(1) Includes minor amounts of coal bed methane and shale gas production.

The Ferrier property in the West Central area accounts for 19,013 BOE/d, or 44.7% of the estimated total production on a proved plus probable basis. This is reflected in the estimate of gross proved plus probable reserves.

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback, before hedging, associated with our assets for the periods indicated below:

	Quarter Ended			
	2013			
	Dec. 31⁽¹⁾	Sept. 30	June 30	Mar. 31
Average Daily Production⁽²⁾				
Light and Medium Crude Oil (Bbls/d)	4,111	3,254	3,657	3,714
Heavy Oil (Bbls/d)	175	195	205	197
Natural Gas (Mcf/d) ⁽³⁾	98,423	93,982	95,376	80,158
NGLs (Bbls/d)	3,278	2,739	2,344	2,072
Combined (BOE/d)	23,968	21,852	22,102	19,343
Average Price Received				
Light and Medium Crude Oil (\$/Bbl)	83.26	102.71	94.84	92.11
Heavy Oil (\$/Bbl)	63.70	86.25	69.28	53.69
Natural Gas (\$/Mcf) ⁽³⁾	3.89	2.68	3.85	3.50
NGLs (\$/Bbl) ⁽⁴⁾	46.20	48.65	36.20	42.30
Combined (\$/BOE)	37.05	33.68	36.78	37.28
Royalties Paid				
Light and Medium Crude Oil (\$/Bbl)	21.67	14.06	22.06	16.14
Heavy Oil (\$/Bbl)	42.09	35.12	19.78	24.14
Natural Gas (\$/Mcf) ⁽³⁾	0.42	0.20	0.19	0.43
NGLs (\$/Bbl)	3.70	5.99	14.82	15.44
Combined (\$/BOE)	6.24	4.04	6.25	6.77
Operating Expenses				
Light and Medium Crude Oil (\$/Bbl)	8.19	9.19	16.98	15.70
Heavy Oil (\$/Bbl)	14.01	12.99	17.21	16.36
Natural Gas (\$/Mcf) ⁽³⁾	1.47	1.48	1.12	1.10
NGLs (\$/Bbl)	8.30	9.05	7.74	8.51
Combined (\$/BOE)	8.70	8.98	8.64	8.65

	Quarter Ended			
	2013			
	Dec. 31 ⁽¹⁾	Sept. 30	June 30	Mar. 31
Netback Received before Transportation				
Light and Medium Crude Oil (\$/Bbl)	53.40	79.46	55.80	60.27
Heavy Oil (\$/Bbl)	7.60	38.14	32.29	13.19
Natural Gas (\$/Mcf) ⁽³⁾	2.00	1.00	2.54	1.97
NGLs (\$/Bbl)	34.20	33.61	13.64	18.35
Combined (\$/BOE)	22.11	20.66	21.89	21.86
Transportation Costs				
Light and Medium Crude Oil (\$/Bbl)	1.40	1.26	1.27	1.37
Heavy Oil (\$/Bbl)	3.27	5.02	3.11	2.68
Natural Gas (\$/Mcf) ⁽³⁾	0.18	0.14	0.14	0.13
NGLs (\$/Bbl)	-	-	-	-
Combined (\$/BOE)	1.01	0.81	0.83	0.83
Netback Received after Transportation⁽⁵⁾				
Light and Medium (\$/Bbl)	52.00	78.20	54.53	58.90
Heavy Oil (\$/Bbl)	4.33	33.12	29.18	10.51
Natural Gas (\$/Mcf) ⁽³⁾	1.82	0.86	2.40	1.84
NGLs (\$/Bbl)	34.20	33.61	13.64	18.35
Combined (\$/BOE)	21.10	19.85	21.06	21.03

Notes:

- (1) Includes 21 days of production from the properties acquired pursuant to the Angle Arrangement.
- (2) Includes minor royalty volumes received but does not deduct royalty volumes paid.
- (3) Includes minor amounts of coal bed methane and shale gas production.
- (4) NGL pricing excludes pentanes.
- (5) Netbacks are calculated by subtracting royalties, operating and transportation costs from revenues.

The following table indicates average daily company share production from important fields in respect of our assets for the year ended December 31, 2013. Company share production includes minor royalty volumes received but does not deduct royalty volumes paid.

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Condensate (Bbls/d)	Natural Gas (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d)
West Central Alberta Region						
Ferrier	1,093	-	974	75,911	2,130	16,849
Greater Pembina	1,058	-	29	2,412	99	1,588
Willesden Green	327	-	50	5,994	233	1,609
Other Properties ⁽¹⁾	107	193	8	7,729	187	1,783
TOTALS⁽²⁾	2,585	193	1,061	92,046	2,649	21,829

Note:

- (1) Includes 21 days of production from properties acquired effective December 11, 2013 pursuant to the Angle Arrangement. For 2014, Bellatrix expects the properties of Harmattan and Strachan, which were acquired in the Angle Arrangement, will represent principal properties, but for 2013, the production volumes from these two properties have been included in "Other Properties".
- (2) May not add due to rounding.

Crude oil production from our assets for the year ended December 31, 2013 was 97% light and medium quality crude oil (25° API or greater) and 3% heavy crude oil (less than 15° API).

For the twelve months ended December 31, 2013, approximately 59.4% of gross revenue from our assets was derived from crude oil and natural gas liquids production and 40.6% was derived from natural gas production.

DIVIDENDS

Bellatrix has not paid any dividends on the outstanding Common Shares. The Board of Directors of Bellatrix 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 of Bellatrix based upon, among other things, the cash flow, results of operations and financial conditions of Bellatrix, the need for funds to finance ongoing operations and other business considerations as the Board of Directors of Bellatrix considers relevant. Bellatrix's current credit facility does not permit payment of dividends on the outstanding Common Shares.

DESCRIPTION OF SHARE CAPITAL

Bellatrix is authorized to issue an unlimited number of Common Shares. Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Bellatrix, to receive dividends if, as and when declared by the Board of Directors of Bellatrix and to receive pro rata the remaining property and assets of Bellatrix upon its dissolution or winding-up, subject to the rights of shares having priority over the Common Shares.

MARKET FOR SECURITIES

Common Shares

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

TSX

Period	High (\$)	Low (\$)	Volume
2013			
January	5.05	4.03	9,223,482
February	5.75	5.02	6,627,721
March	6.70	5.20	10,553,442
April	6.94	5.76	15,874,713
May	6.30	5.44	9,305,727
June	6.48	4.70	15,721,087
July	7.10	6.32	10,087,922
August	7.35	6.70	10,406,442
September	8.02	6.72	19,158,835
October	8.52	7.65	48,474,967
November	7.96	6.65	35,810,175
December	7.93	7.04	20,962,931
2014			
January	8.66	7.64	34,284,312
February	8.45	7.76	13,860,667
March (1 - 20)	9.10	8.29	14,615,955

NYSE MKT

Period	High (US\$)	Low (US\$)	Volume
2013			
January	5.10	4.10	1,121,699
February	5.61	5.00	862,837
March	6.60	5.04	2,046,885
April	6.85	5.63	1,442,211
May	6.25	5.22	1,334,996
June	6.15	4.55	1,545,435
July	6.85	6.00	1,566,766
August	7.50	6.39	1,990,663
September	7.77	6.39	2,167,337
October	8.43	7.41	3,725,862

November	7.63	6.38	3,748,779
December	7.60	6.61	3,509,065
2014			
January	7.88	6.93	3,016,889
February	7.65	7.00	2,508,514
March (1 - 20)	8.20	7.47	2,463,191

ESCROWED SECURITIES

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

BORROWINGS

Senior Credit Facilities

As at December 31, 2013 and as at the date hereof, the Corporation's credit facilities consist of a \$50 million operating facility provided by a Canadian bank and a \$450 million syndicated facility provided by nine financial institutions (the "Credit Facilities"). The Credit Facilities are available on a fully revolving basis until June 24, 2014 (subject to annual extension at the option of the lenders), and if not extended, will be due in full 366 days thereafter. The Credit Facilities will be available to finance Bellatrix's ongoing capital expenditures, working capital requirements and for general corporate purposes. Amounts borrowed under the Credit Facilities will bear interest at a floating rate based on the applicable Canadian prime rate, U.S. base rate, CDOR rate or LIBOR margin rate, plus between 1.00% and 3.50%, depending on the type of borrowing and the Corporation's debt to cash ratio. A standby fee is charged of between 0.50% and 0.875% on the undrawn portion of the Credit Facilities, depending on the Corporation's debt to cash flow ratio. The Credit Facilities are secured by a \$1 billion debenture containing a first ranking charge and security interest. Bellatrix has provided a negative pledge and undertaking to provide fixed charges over its properties in certain circumstances. The amount available under the Credit Facilities is not to exceed the borrowing base, which is currently of \$500 million. The borrowing base will be subject to re-determination on May 31 and November 30 in each year prior to the maturity of the Credit Facilities, with the next semi-annual re-determination occurring on or before May 31, 2014.

DIRECTORS AND OFFICERS

The following table sets forth the name, age (as at December 31, 2013), province or state and country of residence, date first elected as a director of Bellatrix where applicable and office held for each of the directors and officers of Bellatrix together with their principal occupations during the last five years. The directors of Bellatrix shall hold office until the next annual meeting of shareholders or until their respective successors have been duly elected or appointed.

<u>Name, Municipality of Residence and Age</u>	<u>Position with Bellatrix</u>	<u>Date First Elected or Appointed as Director⁽¹⁾</u>	<u>Principal Occupation</u>
Raymond G. Smith, P. Eng. Calgary, Alberta, Canada Age: 66	President, Chief Executive Officer and Director	April 25, 2005	President and Chief Executive Officer of Bellatrix, and prior to November 1, 2009 of True Energy Inc. (as administrator of True Energy Trust), since January 26, 2009. Chairman of Madalena Ventures Inc. since October 2005. From June 2007 to November 2007 President, CEO and Chairman of Cork Exploration Inc. and Chairman of Cork Exploration Inc. from April 2005 to November 2007; from September 2002 to January 2004, Chairman, President and Chief Executive Officer of Meridian Energy Corporation; and Chairman and Chief Executive Officer of Meridian Energy Corporation from January 2004 to March 2005. Prior thereto, Mr. Smith was President and Chief Executive Officer of Corsair Exploration Ltd.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director⁽¹⁾	Principal Occupation
Brent A. Eshleman, P. Eng. Calgary, Alberta, Canada Age: 49	Executive Vice-President	N/A	Executive Vice President of Bellatrix since July 2012. Prior thereto, from December 2004 to January 2012, Vice President Engineering and Exploitation of Daylight Energy Ltd. From May 2000 to November 2004 Director, Northern Alberta of Calpine Canada. From May 1998 to April 2000 Manager Engineering of Ulster Petroleum Ltd.
Edward J. Brown, C.A. Calgary, Alberta, Canada Age: 58	Executive Vice-President, Finance and Chief Financial Officer	N/A	Executive Vice-President, Finance and Chief Financial Officer of Bellatrix since April 1, 2013 and prior thereto Vice-President, Finance and Chief Financial Officer. From July 4, 2006 to November 1, 2009, Vice-President, Finance and Chief Financial Officer of True Energy Inc. (as administrator of True Energy Trust); prior thereto, from March 2005 to June 2006, Vice-President, Finance and Chief Financial Officer of Petrofund Energy Trust; from February 2002 to March 2005, senior financial officer of Duke Energy Field Services.
Ving Y. Woo, P. Eng. Calgary, Alberta, Canada Age: 65	Vice President and Chief Operating Officer	N/A	Vice-President and Chief Operating Officer of Bellatrix, since October 2010; prior thereto Vice President, Operations of Bellatrix and, prior to November 1, 2009, of True Energy Inc. (as administrator of True Energy Trust), since April 2009. Currently director of Madalena Ventures Inc. since March 2006 and formerly a Director of Cork Exploration Inc., a public oil and gas company. Formerly Vice President, Engineering for Meridian Energy Corp. from September 2002 until March 2005.
Russell G. Oicle P. Geol. Calgary, Alberta, Canada Age: 58	Vice-President, Exploration	N/A	Vice-President, Exploration of Bellatrix and, prior to November 1, 2009, of True Energy Inc. (as administrator of True Energy Trust), since November 24, 2008; prior thereto, from July 2007 to November 2008, Exploration Supervisor of Penn West Energy Trust; from May 2005 to July 2007, President, RGO Resources, a private geological consulting company; from November 2002 to May 2005, Vice President, Exploration and Chief Operating Officer of Relentless Energy Corp.; prior thereto, Vice President of Exploration of Ulster Petroleums Ltd.
Timothy A. Blair Cochrane, Alberta, Canada Age: 55	Vice President, Land	N/A	Vice President, Land of Bellatrix, and prior to November 1, 2009 of True Energy Inc. (as administrator of True Energy Trust), since October 2009; prior thereto was Vice President, Land for Terra Energy Corp. from June 2004 to September 2009

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director⁽¹⁾	Principal Occupation
Garrett K. Ulmer, P. Eng. Calgary, Alberta, Canada Age: 43	Vice President, Engineering	N/A/	Vice-President, Engineering of Bellatrix since October 2011. Prior thereto, held roles of Production Engineer, Production Manager, and Manager of Exploitation and Acquisitions of Bellatrix, and prior to November 1, 2009 of True Energy Inc. (as administrator of True Energy Trust), since January 2008.
Kelly M. Nichol Calgary, Alberta, Canada Age: 48	Vice-President, Business Development	N/A	Vice-President, Business Development of the Corporation since May 2013 and prior thereto a business development consultant to the Corporation since 2012. Formerly Vice President, Business Development with Daylight Energy Ltd. from 2008 to 2012.
Leanne K. Gress-Blue, C.A. Calgary, Alberta, Canada Age: 45	Vice-President, Finance	N/A	Vice-President, Finance of Bellatrix since April 1, 2013 and prior thereto Treasurer of Bellatrix. Prior to November 1, 2009, Treasurer of True Energy Inc. (as administrator of True Energy Trust).
W.C. (Mickey) Dunn Calgary, Alberta, Canada Age: 60	Chairman ⁽⁴⁾⁽⁵⁾	August 31, 2000	Chairman of Bellatrix and prior to November 1, 2009 of True Energy Inc. (as administrator of True Energy Trust); Director of Precision Drilling Inc.; Director of The Cash Store Financial Services Inc.; previously President and Chief Executive Officer of Cardium Service and Supply Ltd. and Cardium Tool Services Inc. from 1981 to 1999, and Colorado Silica Sand Inc. from 1981 to 1996.
Doug N. Baker, FCA Calgary, Alberta, Canada Age: 60	Director ⁽²⁾⁽⁵⁾	April 26, 2007	Independent businessman. Mr. Baker currently serves as a director of ATB Financial Ltd. and is a director and Chair of the Audit Committee for RMP Energy Inc., Longview Oil Corp., and Century Energy Ltd. Served as Chair of the Canadian Institute of Chartered Accountants from 2008 to 2010.
Murray L. Cobbe Calgary, Alberta, Canada Age: 64	Director ⁽³⁾⁽⁴⁾	September 22, 2006	Chairman and, prior to August 2009, President and Chief Executive Officer of Trican Well Service Ltd. (a publicly traded well service company). Director of Pason Systems Inc. since 2001. Director of Secure Energy Services Inc. since 2009.
John H. Cuthbertson, Q.C. Calgary, Alberta, Canada Age: 63	Director ⁽⁵⁾	August 31, 2000	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Melvin M. Hawkrigg, BA, FCA, LL.D. (Hon.) Waterdown, Ontario, Canada Age: 83	Director ⁽²⁾	March 31, 2009	Chairman, Orlick Industries Limited, a private automotive supply company from 1998.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director⁽¹⁾	Principal Occupation
Robert A. Johnson, P.Geol. Calgary, Alberta, Canada Age: 77	Director ⁽³⁾	September 21, 2009	Independent businessman. Executive Vice-President of Grey Wolf Exploration Inc. from 2000 to July 2009.
Keith E. Macdonald, C.A. Calgary, Alberta, Canada Age: 57	Director ⁽²⁾⁽⁴⁾	April 26, 2007	President of Bamako Investment Management Ltd., a private holding and financial consulting company, since July 1994. Mr. Macdonald is currently the Chief Executive Officer and a director of EFLO Energy Inc. and has held such positions since March 2011.
Murray B. Todd, B. Sc. P. Eng. Calgary, Alberta, Canada Age: 78	Director ⁽³⁾	November 2, 2005	President of Canada Hibernia Holding Corporation (an oil and gas production company).
Keith Turnbull, B.Sc. C.A. Calgary, Alberta, Canada Age: 64	Director ⁽²⁾	January 1, 2014	Business consultant since January 1, 2010. Prior thereto, Partner at KPMG LLP. President of K.S. Turnbull Professional Corporation and currently a Director of Renegade Petroleum Ltd. and Crown Point Energy Inc.

Notes:

- (1) Reflects the date of election or appointment as Director of True Energy Inc. (administrator of True Energy Trust).
- (2) Member of Audit Committee.
- (3) Member of Reserves, Safety and Environment Committee.
- (4) Member of Compensation Committee.
- (5) Member of Corporate Governance Committee.
- (6) The term of each director is until the next annual meeting of Bellatrix or until their successors are elected, but not later than the date of the next annual meeting of Bellatrix.

As at February 28, 2014, the directors and officers of Bellatrix, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 2,641,194 Common Shares, representing approximately 1.54% of the issued and outstanding Common Shares.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Bellatrix will be subject to in connection with the operations of Bellatrix. In particular, certain of the directors and officers of Bellatrix 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 Bellatrix 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 Bellatrix are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate of the Audit Committee of the board of directors of Bellatrix is attached hereto as Schedule "C".

Composition of the Audit Committee

The following table sets forth the names of each current member of the Audit Committee, whether such member is independent, whether such member is financially literate and the relevant education and experience of each such member:

<u>Name and municipality of residence</u>	<u>Independent</u>	<u>Financially literate</u>	<u>Relevant education and experience</u>
Doug N. Baker, FCA Calgary, Alberta, Canada	Yes	Yes	Mr. Baker, who served as the Chair of the Canadian Institute of Chartered Accountants from 2008 to 2010, and served as the President of the Institute of Chartered Accountants of Alberta in 2003, brings considerable experience in finance, tax and accounting to the Audit Committee. An independent businessman, Mr. Baker currently serves as a director of ATB Financial Ltd. and as a director and Chair of the Audit Committee for RMP Energy Inc., Longview Oil Corp. and Century Energy Ltd. Prior thereto Mr. Baker was Chief Financial Officer of Valiant Energy Inc. and predecessor companies, Forte Resources Inc. and Forte Energy Ltd. from 1997 to 2006. Prior to 1997 Mr. Baker held senior financial positions in several public companies. Mr. Baker is a graduate of the University of Saskatchewan and holds a Bachelor of Commerce degree with Honours and Distinction. He has been a chartered accountant since 1977. In 1996, Mr. Baker received the honour of being named a Fellow of Chartered Accountants.
Melvin M. Hawkrigg, BA, FCA, LL.D (Hon.) Waterdown, Ontario, Canada	Yes	Yes	Mr. Hawkrigg is the Chairman of Orlick Industries Limited, a private automotive supply company and has held such position since 1998. Mr. Hawkrigg has served as a board and audit committee member for a number of Canadian public corporations. Mr. Hawkrigg holds a Bachelor of Arts from McMaster University, received the honour of being a Fellow of the Institute of Chartered Accountants in 1985 and received an Honorary Doctor of Laws degree from McMaster University in 1997.
Keith E. Macdonald, CA Calgary, Alberta, Canada	Yes	Yes	Mr. Macdonald is the President of Bamako Investment Management Ltd., a private holding and financial consulting company and has held such position since July 1994. Mr. Macdonald is currently the Chief Executive Officer and a director of EFLO Energy Inc. and has held such positions since March 2011. He is also a director of Surge Energy Inc., Madalena Ventures Inc. and Mountainview Energy Ltd. Mr. MacDonald is a Chartered Accountant.
Keith Turnbull, B.Sc. CA Calgary, Alberta, Canada	Yes	Yes	Mr. Turnbull is a Chartered Accountant and has been a business consultant since his retirement as a Partner from KPMG on December 31, 2009, after nearly 30 years of service. Mr. Turnbull has extensive experience in all aspects of public company accounting, finance and management matters, including serving as Office Managing Partner at KPMG's Calgary office, where he was responsible for the strategic direction and growth of the Calgary practice, as well its audit, tax and advisory business. Mr. Turnbull is a member of the Alberta and Canadian Institute of Chartered Accountants and the Institute of Corporate Directors. Mr. Turnbull is currently a director and audit committee member of Crown Point Energy Inc. and Renegade Petroleum Ltd.

Pre-Approval Policies and Procedures

The Audit Committee has adopted an Auditor Services Pre-Approval Policy (the "**Policy**") with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP, the Corporation's independent auditor. Pursuant to the Policy, the Audit Committee on an annual basis may approve the provision of a specified list of audit and permitted non-audit services that the Audit Committee believes to be typical, re-occurring or otherwise likely to be provided by KPMG LLP during the current fiscal year. The list of services should be sufficiently detailed as to the particular services to be provided to ensure that the Audit Committee knows precisely what services it is being asked to pre-approve and it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services.

In addition, pursuant to the Policy the Audit Committee has delegated its pre-approval authority to the Chair of the Audit Committee. The Chair of the Audit Committee is required to report any granted pre-approvals to the Audit Committee at its next scheduled meeting. The Audit Committee shall not delegate to management the Audit Committee's responsibilities for pre-approving audit and non-audit services to be performed by KPMG LLP.

Pursuant to the Policy, there is an exception to the pre-approval requirements for permitted non-audit services, provided all such services were not recognized at the time of the engagement to be non-audit services and, once recognized, are promptly brought to the attention of the Audit Committee and approved prior to the completion of the audit. The aggregate amount of all services approved in this manner may not constitute more than five percent of the total fees paid to KPMG LLP during the fiscal year in which the services are provided.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by Bellatrix's external auditor in each of the last two fiscal years for audit services including the annual audit, reviews of interim consolidated financial statements, internal control compliance, international financial reporting standards, compliance for NYSE MKT listing and due diligence work in respect of financings and a corporate acquisition were \$657,200 in 2013 and \$665,550 in 2012.

Audit – Related Fees

There were \$111,180 in 2013 and \$129,540 in 2012 billed for French translation services by the external auditor that are reasonably related to the performance of the audit or review of the financial statements that are not reported under "*Audit Fees*" above.

Tax Fees

No fees were billed for professional services rendered by the external auditor for tax compliance, tax advice and tax planning in 2013 or 2012.

All Other Fees

No other professional services fees were billed by the external auditor for other non-audit related fees in 2013 or 2012.

INDUSTRY CONDITIONS

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

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* which received Royal Assent on June 29, 2012 (the "**Prosperity Act**"). In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m³/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

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

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

Royalties and Incentives

General

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

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

Alberta

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

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

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

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

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "IETP") has the stated objectives of increasing recovery from oil and gas deposits, finding technical

solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

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

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

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

British Columbia

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

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20% of the sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold natural gas liquids is a flat rate of 12.25%.

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

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs. Effective on April 1, 2014, the Deep Well Royalty Credit Program will have two tiers—"tier one" and "tier two". The existing Deep Well Royalty Credit Program, as described above, will comprise tier two of the program. Tier one of the Deep Well Royalty Credit Program will apply to shallower horizontal wells with a true vertical depth less than 1,900 metres if spud after March 31, 2014;
- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;
- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m³ of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;
- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m³ as well as a royalty credit for coalbed gas wells equal to \$50,000 for wells drilled on Crown land and a tax credit equal to \$30,000 for wells drilled on freehold land;
- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m³ for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000m³;
- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17m³ per metre of depth for exploratory wildcat wells and less than 11m³ per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000m³. Effective on April 1, 2014, the Ultra-Marginal Royalty Reduction Program will no longer apply to horizontal wells due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; and
- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well that is located on either Crown or freehold land and completed in a new pool discovered subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m³ of production, whichever comes first.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 3% minimum royalty on affected wells with deep well/deep re-entry credits. The 3% minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month.

Saskatchewan

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

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m³ for "old oil", "new oil" and "third tier oil", and 250 m³ per month for "fourth tier oil". Where average wellhead prices are below the established base prices of \$100 per m³ for third and fourth tier oil and \$50 per m³ for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government, the quantity produced in a given month, the type of natural gas, and the classification of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m³ of gas for every m³ of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

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

As with conventional oil production, base prices based on a well reference rate of 250 10³ m³/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of \$1.35 per gigajoule for third and fourth tier gas and \$0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas. The current regulatory scheme provides for certain differences with respect to the administration of "fourth tier gas" which is associated gas.

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

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m³ for deep development vertical oil wells, 4,000 m³ for non-deep exploratory vertical oil wells and 16,000 m³ for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;
- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m³ for qualifying exploratory gas wells;
- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 m³ for non-deep horizontal oil wells and 16,000 m³ for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;
- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m³ for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;
- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing lower Crown royalty and freehold tax determinations based in part on the profitability of EOR projects during and subsequent to the payout of the EOR operations;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on EOR projects pre-payout

and 20% of EOR operating income post-payout and a freehold production tax of 0% pre-payout and 8% post-payout on operating income from EOR projects; and

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

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

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

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

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

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

Federal

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

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy

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

In December 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

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

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

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

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

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

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act* requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Saskatchewan

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

Liability Management Rating Programs

Alberta

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

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

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);
- a \$7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and
- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

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

British Columbia

In British Columbia, the Commission implements the Liability Management Rating ("**LMR**") Program, designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the LMR Program, the Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

Saskatchewan

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

Climate Change Regulation

Federal

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

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-

Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

Alberta

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

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year and 10% of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of \$15 per tonne of CO₂ equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest \$2 billion into demonstration projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

British Columbia

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is \$30 per tonne of CO₂ equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

In the 2012 Budget, British Columbia announced that the government would undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review last year, British Columbia confirmed that it will keep its revenue-neutral carbon tax, the current carbon tax rates and tax base will be maintained and revenues will continue to be returned through tax reductions.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**"), which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33% reduction in the 2007 level of GHG emissions by 2020 and an 80% reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. The *Reporting Regulation*, implemented under the authority of the Cap and Trade Act, sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Recent amendments to the Cap and Trade Act repealed past requirements on public-sector organizations, including Crown corporations, to be carbon neutral by 2010, and they are now only required to produce annual carbon reduction plans and reports. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under development.

Saskatchewan

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

RISK FACTORS

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.

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. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

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

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

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. While there are signs of economic recovery, these factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, actions taken by 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.

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 United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could

result in reduced production of oil or natural gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

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

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, 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.

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 of the Corporation 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 of the Corporation will trade cannot be accurately predicted.

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.

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.

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 limit 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, in turn, the Corporation's 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 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 oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake. 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).

Royalty Regimes

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

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, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the 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 greenhouse gases and which may require the Corporation to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. 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 in greenhouse gas ("GHG") emissions from 2005 levels by 2020. 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, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition.

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

Substantial Capital Requirements

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

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- interest rates;
- royalty rates;

- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

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

Additional Funding Requirements

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

Because of 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.

Credit Facility Arrangements

The Corporation currently has a credit facility and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its credit facility and in the event that the Corporation does not comply with these covenants, the Corporation's access to capital could be restricted or repayment could be required. Events beyond the Corporation's control may contribute to the failure of the Corporation to comply with such covenants. A failure to comply with covenants could result in the default under the Corporation's credit facility, which could result in the Corporation being required to repay amounts owing thereunder. Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under credit facilities, the lenders under the credit facility could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's credit facility may impose operating and financial restrictions on the Corporation that could include restrictions on the payment of dividends, 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 lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility which could result in the requirement to repay a portion, or all, of the Corporation's bank indebtedness.

Issuance of Debt

From time to time, the Corporation may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above

industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

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

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

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar. However, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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

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 document 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 will result in variations in the estimated reserves. Such variations could be material.

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

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

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.

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.

Ability of Residents of the United States to Enforce Civil Remedies

Bellatrix is organized under the laws of Alberta, Canada and our principal places of business are in Canada. Most of our directors and all of our officers and the experts named herein are residents of Canada, and a substantial portion of our assets and all or a substantial portion of the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon those directors, officers and experts who are not residents of the United States or to enforce against them judgments of United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or against any of our directors, officers or experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or the securities laws of any state within the United States.

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 United States companies.

The primary differences between the Canadian and United States 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 shares. Payment of dividends in the future 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.

Aboriginal Claims

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

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 all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

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

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation 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 or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director 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 the 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 the Western Canada Sedimentary Basin. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Forward-Looking Information May Prove Inaccurate

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

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

HUMAN RESOURCES

As at December 31, 2013 Bellatrix employed 145 full-time employees (110 are located in the head office and 35 are field employees) and 56 consultants (55 full-time and 1 part-time consultant of which 13 are located in the head office and 43 are in the field).

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of Bellatrix, 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 Bellatrix.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than Sproule, the Corporation's independent engineering evaluators and KPMG LLP, the Corporation's auditors. None of Sproule or the "designated professionals" (as defined in Item 16.2(1.1) of Form 51-102F2 of National Instrument 51-102 of the Canadian Securities Administrators) of Sproule have or are to receive any registered or beneficial interest, direct or indirect, in any of Bellatrix's securities or other property of Bellatrix or of Bellatrix's associates or affiliates, either at the time Sproule prepared the report, valuation, statement or opinion or any time thereafter. KPMG 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 and also that they are independent accountants with respect to the Corporation under all relevant United States professional and regulatory standards.

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 associate or affiliate of the Corporation.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Other than as described below, Bellatrix is not a party to any legal proceeding nor was it a party to any legal proceeding during the 2013 financial year, nor is Bellatrix aware of any contemplated legal proceeding involving Bellatrix, 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 Bellatrix.

On December 6, 2013, prior to the completion of the Angle Arrangement, a Statement of Claim was filed in the Court of Queen's Bench of Alberta against Angle alleging that certain of Angle's operational activities at five wells located on properties surrounding the plaintiff's home had caused damage to the plaintiff's land. The claim seeks general damages of \$8,000,000.00, special damages of \$405,577.50, and punitive damages of \$5,000,000.00, for a total claim of \$13,405,577.50 in damages. Bellatrix filed a Statement of Defence on February 7, 2014. Document production has yet to take place and this matter has not yet proceeded to questioning.

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

MATERIAL CONTRACTS

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

A copy of this document has been filed on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of Bellatrix are KPMG LLP, Chartered Accountants, Suite 2700, 205 - 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

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. The co-transfer agent and registrar for the Common Shares in the United States is Computershare Investor Services US at its principal office in Golden, Colorado.

ADDITIONAL INFORMATION

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

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:

Bellatrix Exploration Ltd.
Suite 1920, 800 - 5th Avenue S.W.
Calgary, Alberta T2P 3T6
Tel: (403) 266-8670
Fax: (403) 264-8163

SCHEDULE "A"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Bellatrix Exploration Ltd. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013 estimated using forecast prices and costs.

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

The Reserves Committee of the board of directors of the Corporation has

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

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

- (a) the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;
- (b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and
- (c) the content and filing of this report.

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

DATED as of this 21st day of March, 2014.

(signed) "*Raymond G. Smith*"
Raymond G. Smith, P.Eng.
President and Chief Executive Officer

(signed) "*Edward J. Brown*"
Edward J. Brown, C.A.
Executive Vice-President, Finance and Chief Financial Officer

(signed) "*Murray B. Todd*"
Murray B. Todd
Director

(signed) "*Robert A. Johnson*"
Robert A. Johnson
Director

SCHEDULE "B"
FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Bellatrix Exploration Ltd. (the "**Company**"):

1. We have evaluated the Company's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013 estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Corporation's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Corporation evaluated by us as of December 31, 2013, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's Board of Directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
Sproule Associates Limited	Evaluation of the P&NG Reserves of Bellatrix Exploration Ltd., As of December 31, 2013, prepared November 2013 to March 2014	Canada	Nil	2,090,071	Nil	2,090,071

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after its respective preparation date.

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

EXECUTED as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
March 4, 2014

Per: (signed) "Geoff W. Beatson, P. Eng."
Senior Engineering Advisor and Partner

Per: (signed) "Doug McNichol, P.Eng."
Senior Petroleum Engineer and Associate

Per: (signed) "Rod Fradette, P. Eng."
Senior Petroleum Engineer and Associate

Per: (signed) "James D. Hudson, P.L. (Eng.)"
Senior Petroleum Technologist and Partner

Per: (signed) "David M. Shewchuk, C.E.T."
Senior Petroleum Engineering Technician

Per: (signed) "Pavitra Iyer, E.I.T."
Engineer-in-Training

Per: (signed) "Tin Duong, E.I.T."
Engineer-in-Training

Per: (signed) "George Strother-Stewart, P.Geol."
Senior Petroleum Geologist and Partner

Per: (signed) "Alec Kovaltchouk, P.Geol."
Manager, Geoscience and Partner

Per: (signed) "Harry J. Helwerda, P.Eng., FEC, FGC (Hon.)"
President, Chief Operating Officer and Director

SCHEDULE "C"
MANDATE AND TERMS OF REFERENCE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Bellatrix Exploration Ltd. ("**Bellatrix**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the following:

1. nature and scope of the annual audit;
2. the oversight of management's reporting on internal accounting standards and practices;
3. the review of financial information, accounting systems and procedures including internal control over financial reporting;
4. financial reporting and financial statements,

and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist directors of Bellatrix ("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 oversee the accounting and financial reporting processes of Bellatrix and the audits of Bellatrix's financial statements;
3. To provide better communication between Directors and external auditors;
4. To review and enhance the external auditor's independence;
5. To increase the credibility and objectivity of financial reports; and
6. To strengthen the role of the outside Directors by facilitating in depth discussions between Directors on the Committee, management of Bellatrix ("**Management**") and external auditors.

The Committee, in its capacity as a committee of the Board and subject to the rights of shareholders of Bellatrix and applicable law, is directly responsible for overseeing the relationship of the external auditors with Bellatrix, including the appointment, termination, compensation, retention and oversight of the work of the external auditors engaged by Bellatrix (including resolution of disagreements or disputes between Management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for Bellatrix.

The external auditor will report directly to the Committee.

Membership of Committee

1. The Committee will be comprised of at least three (3) Directors or such greater number as the Board may determine from time to time and all members of the Committee shall qualify as independent for purposes of (a) National Instrument 52-110 — Audit Committees ("NI 52-110") (unless the Board determines that an exemption contained in NI 52-110 is available and determines to rely thereon); (b) the rules of the NYSE MKT; and (c) Rule 10A-3 ("Rule 10A-3") under the United States Securities Exchange Act of 1934, as

amended, (the "1934 Act") (unless the Board determines that an exemption contained in Rule 10A-3 is available and determines to rely thereon).

2. No member of the Committee shall have participated in the preparation of the financial statements of Bellatrix or any current subsidiary of Bellatrix at any time during the prior three years.
3. At least one member of the Committee shall be an "audit committee financial expert" within the meaning of that term under the 1934 Act and the rules adopted by the United States Securities and Exchange Commission (the "SEC") thereunder, unless the Board determines that the Committee shall not include an audit committee financial expert and provides the necessary disclosure with respect to such determination as required under the 1934 Act and the rules of the SEC thereunder. If at least one member of the Committee is not determined to be an audit committee financial expert then at least one member of the Committee shall be "financially sophisticated" within the meaning of the rules of the NYSE MKT.
4. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.
5. All of the members of the Committee must have the ability to read and understand a set of financial statements, including a balance sheet, income statement, and cash flow statement (or such other comparable statements as are required under generally accepted accounting principles), that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Bellatrix's financial statements, and shall meet any other financial literacy requirements for audit committee members that may be imposed from time to time under Canadian or United States securities laws or any applicable stock exchange rules, unless the Board determines that an exemption from such requirements in respect of any particular member is available and determines to rely thereon.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors;
2. Satisfy itself on behalf of the Board with respect to Bellatrix's internal control systems identifying, monitoring and mitigating business risks; and ensuring compliance with legal, ethical and regulatory requirements;
3. Review and discuss with Management all significant commitments and business risks related to such commitments including, without limitation, commitments associated with farm-in agreements, joint-venture agreements, leases, marketing or transportation arrangements or agreements and all other operational or land agreements, contracts or arrangements;
4. Review and discuss with Management and the external auditors the annual and interim financial statements of the Corporation and related management's discussion and analysis ("MD&A") prior to their submission to the Board for approval and inclusion in securities law filings. The process should include but not be limited to:
 - (a) reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
 - (b) reviewing significant accruals, reserves or other significant estimates;
 - (c) reviewing accounting treatment of unusual or non-recurring transactions;
 - (d) ascertaining compliance with covenants under loan agreements;
 - (e) reviewing disclosure requirements for commitments and contingencies;

- (f) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
 - (g) reviewing unresolved differences between Management and the external auditors; and
 - (h) obtaining explanations of significant variances with comparative reporting periods;
5. Review the financial statements, prospectuses, MD&A, annual information forms ("AIF"), annual reports filed with the SEC, and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Bellatrix's disclosure of all other financial information and will periodically assess the accuracy of those procedures;
 6. Meet with the external auditors annually prior to commencement of the audit to discuss planning and staffing of the audit;
 7. On an annual basis, review and discuss with the external auditors all relationships such auditors have with Bellatrix and its affiliates in order to determine the auditors' independence, including without limitation:
 - (a) requesting, receiving and reviewing, on a periodic basis but at least annually, a formal written statement, consistent with applicable accounting standards, from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to Bellatrix;
 - (b) discussing with the external auditors any disclosed relationships or services that may affect the objectivity and independence of the external auditors; and
 - (c) taking, or recommending that the Board take, appropriate action to oversee the independence of the external auditors and to take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence;
 8. When there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;
 9. Review and discuss a report from the external auditors, at a minimum once quarterly and generally in conjunction with the review of any audit or review report prepared by the external auditors with respect to the annual or interim financial statements of the Corporation, regarding:
 - (a) all critical accounting policies and practices to be used;
 - (b) all alternative treatments of financial information within applicable generally accepted accounting principles that have been discussed with Management, including the ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditors; and
 - (c) other material written communications between the external auditors and Management, such as any management letter or schedule of unadjusted differences;
 10. Review and pre-approve, subject to any *de minimis* exceptions available under applicable laws, all audit and permitted non-audit services, including the terms thereof and the fees related thereto, to be provided to Bellatrix or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may establish detailed policies and procedures for pre-approval of the provision of audit services and permitted non-audit services by the external auditors. To the extent permitted by applicable laws, the Committee may delegate to one or more independent members of the Committee the authority to pre-approve such audit and non-audit services, provided (i) that such delegation must be detailed as to the particular service to be provided, (ii) the Committee's responsibilities may not be

delegated to Management of Bellatrix, (iii) the applicable member(s) must report to the Committee at the next scheduled meeting such pre-approval, and (iv) such member(s) comply with such other procedures as may be established by the Committee from time to time;

11. Discuss with the external auditors any audit problems or difficulties, including any difficulties encountered in the course of the audit work, restrictions on the scope of the external auditor's activities or on access to requested information, any significant disagreements with Management, and Management's response;
12. Review with the external auditors the disclosures made to the Committee by Bellatrix's Chief Executive Officer and Chief Financial Officer during their certification process. In particular, the Committee shall review with the Chief Executive Officer, Chief Financial Officer and external auditors: (i) all significant deficiencies and material weaknesses in the design or operation of Bellatrix's internal control over financial reporting that could adversely affect Bellatrix's ability to record, process, summarize and report financial information required to be disclosed by Bellatrix in the reports that it files or submits under any applicable Canadian securities laws or the 1934 Act within the required time periods, and (ii) any fraud, whether or not material, that involves Management or other employees who have a significant role in Bellatrix's internal control over financial reporting;
13. Annually discuss with the external auditors whether they have become aware of any illegal acts in the course of the audit of Bellatrix's financial statements;
14. Review with external auditors (and internal auditor if one is appointed by Bellatrix) their assessment, if any, of the internal controls of Bellatrix, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Bellatrix and its subsidiaries;
15. Review risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance);
16. Establish procedures for:
 - (a) the receipt, retention and treatment of complaints received by Bellatrix regarding accounting, internal accounting controls or auditing matters; and
 - (b) the confidential, anonymous submission by employees of Bellatrix of concerns regarding questionable accounting or auditing matters;
17. Review and approve Bellatrix's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation;
18. Ensure the rotation of partners on the audit engagement team of the external auditors in accordance with applicable law; and
19. Review periodically, as determined necessary, the Committee's Mandate and Terms of Reference and recommend to the Board and the Corporate Governance Committee of the Board amendments as the Committee believes are necessary or desirable.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Bellatrix. All employees of Bellatrix are to cooperate as requested by the Committee.

The Committee may also retain, at the expense of Bellatrix, persons having special expertise and/or obtain independent professional advice, including, without limitation, independent counsel or other advisors, as the Committee determines is necessary in order for the Committee to carry out its duties.

Bellatrix shall provide, without any further approval of the Board required, for appropriate funding, as determined by the Committee, in its capacity as a committee of the Board, for payment: (i) of compensation to any external auditors engaged for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for Bellatrix, (ii) of compensation to any advisors or other persons employed by the Committee; and (iii) of ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties.

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.
2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.
3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.
4. Meetings of the Committee should be scheduled to take place at least quarterly. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer of Bellatrix will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.
5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.
6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.
7. The Committee may invite such officers, directors and employees of the Corporation and its subsidiaries as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.
8. Minutes of the Committee will be recorded and maintained and circulated to Directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.
9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation as determined by the Committee.
10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a Director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee each member will hold such office until the Committee is reconstituted.
11. Any issues arising from these meetings that bear on the relationship between the Board and Management should be communicated to the Chairman of the Board by the Committee Chair.

September 24, 2012