ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2012

March 15, 2013

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ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
Bbls/d	barrels per day	Bcf	billion cubic feet
BOPD	barrels of oil per day	GJ	gigajoule
NGLs	natural gas liquids	GJ/d	gigajoules per day
STB	stock tank barrels	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, 2012 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);

"**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.

"**Joint Venture**" has the meaning ascribed to such term under the heading "*General Development of Our Business – Recent Developments*";

"**JV Partner**" has the meaning ascribed to such term under the heading "*General Development of Our Business – Recent Developments*";

"**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*;

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

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

"**Sproule Report**" means the report of Sproule dated March 5, 2013 evaluating our crude oil, natural gas liquids and natural gas reserves as at December 31, 2012; 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, 2012.

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, the expected timing for satisfying or waiving certain conditions for closing the Joint Venture and timing for closing the Joint Venture, the additional capital expected to be available to the Corporation as a result of the Joint Venture, the expected changes to the Corporation's capital expenditure plans and future development schedule resulting from the Joint Venture, 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, risks that the Joint Venture won't close or, if it closes, that it won't be on the terms expected, risks that the JV Partner (as defined herein) will not be able to fund its required portion of capital expenditures, 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; that the Joint Venture will close on the timing and terms expected, that the JV Partner will have the necessary capital to fund its obligations pursuant to the Joint Venture, 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.

Bellatrix's principal and head office is located at 2300, 530 – 8th Avenue S.W., Calgary, Alberta, T2P 3S8 and its registered office is located at 2400, 525 – 8th Ave SW Calgary, AB T2P 1G1.

Bellatrix does not have, and at December 31, 2012 did not have, any material subsidiaries.

The Common Shares trade on the TSX and the NYSE MKT under the symbol "BXE" and the 4.75% Debentures trade on the TSX under the symbol "BXE.DB.A".

GENERAL DEVELOPMENT OF OUR BUSINESS

The following is a summary description of the development of our business since January 1, 2010.

2010 Public Offering of Common Shares

On January 28, 2010, the Corporation completed a public offering of an aggregate of 13,640,000 Common Shares at a price of $3.30 per Common Share for aggregate gross proceeds of $45,012,000.

2010 Public Offering of 4.75% Debentures and Redemption of 7.50% Debentures

On April 20, 2010, the Corporation completed a public offering of 4.75% Debentures having an aggregate principal amount of $55,000,000. The proceeds from the issuance of the 4.75% Debentures were used to partially fund the redemption of 7.50% convertible unsecured subordinated debentures of the Corporation and the balance of the redemption amount was funded through bank indebtedness. The 7.50% convertible unsecured subordinated debentures of the Corporation were redeemed on July 2, 2010 for an amount of $1,025 for each $1,000 principal amount of such debentures plus accrued and unpaid interest.

2010 Private Placement of Flow-Through Shares

On August 12, 2010, the Corporation completed a private placement of an aggregate of 4,710,000 Common Shares issued on a "flow-through" basis at a price of $4.25 per share for aggregate gross proceeds of $20,017,500.

2010 Asset Divestiture

On December 22, 2010, the Corporation completed the sale of its interest in a non-core property at Mantario, Saskatchewan for net proceeds of $13.6 million after adjustments. The property had annual production of 290 BOE/d that consisted primarily of heavy oil. The effective date of the sale was December 1, 2010.

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.

Recent Developments

On January 23, 2013, Bellatrix entered into a joint venture agreement with a Seoul Korea based company (the "**JV Partner**"), to accelerate development of Bellatrix's extensive undeveloped Cardium land holdings in west-central Alberta. Under the terms of the agreement, the JV Partner will contribute 50%, or $150 million, to a $300 million joint venture (the "**Joint Venture**") to participate in an expected 83 Cardium well program. Under the agreement, the

JV Partner will earn 33% of Bellatrix's working interest in the Cardium well program until payout (being recovery of the JV Partner's capital investment plus an 8% return on investment) on the total program, which is expected to occur prior to a maximum of 7 years, reverting to a 20% working interest after payout. The effective date of the agreement is April 1, 2013 but with the ability of the JV Partner to elect to invest in the wells drilled between January 1 and April 30, 2013. Certain conditions precedent are expected to be satisfied or waived by April 22, 2013 which is expected to enable closing to occur on or before April 30, 2013. Bellatrix will be required to provide a guarantee to a maximum of $30 million if the JV Partner receives less than a full return on their capital investment within 7 years.

Significant Acquisitions

We did not complete any significant acquisitions during our most recently completed financial year for which disclosure is required under Part 8 of NI 51-102.

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. 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 5, 2013. The effective date of the Statement is December 31, 2012 and the preparation date of the Statement is March 5, 2013.

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, 2012. 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.

Effect of Joint Venture on Reserves Data

As disclosed under Recent Developments, Bellatrix has entered into a Joint Venture to accelerate Cardium development in west-central Alberta. Within the context of the Sproule Report, select undeveloped reserves as evaluated at December 31, 2012 will be impacted by the Joint Venture. There will be no impact to proved or probable developed reserves, undeveloped reserves outside the Cardium formation, or undeveloped reserves outside the Joint Venture lands. The Sproule Report includes 49 gross and 48 net Cardium future development locations which would be impacted at the closing of the Joint Venture. This represents 30% gross and 43% net of the total Cardium future development locations evaluated by Sproule. In accordance with the terms of the agreement, the JV Partner would be responsible for 50% of the future development costs associated with these locations and, as a result, Bellatrix's obligations for future development costs associated with these locations would be reduced from 100% to 50%. In addition, the Joint Venture will result in Bellatrix's working interest in these locations being reduced from 100% to 67% before program payout. At program payout, Bellatrix working interest would revert from 67% to 80%. The Joint Venture contemplates additional Cardium development which is not included in the Sproule Report. Any impact of the Joint Venture on Bellatrix's Cardium undeveloped reserves and the associated future net revenue will only result when and if the Joint Venture closes. See "*General Development of Our Business – Recent Developments"*.

Reserves Data (Forecast Prices and Costs)

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS**

	Light And Medium Oil		Heavy Oil		Natural Gas[1]		Natural Gas Liquids	
Reserves Category	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbls)**	**Net (Mbbls)**
Proved Developed Producing	5,337	4,159	68	52	91,664	72,206	3,787	2,253
Proved Developed Non-Producing	13	9	-	-	787	641	22	12
Proved Undeveloped	5,119	4,287	113	86	120,898	93,809	5,200	3,527
Total Proved	10,468	8,455	181	138	213,348	166,656	9,008	5,793
Probable	6,058	4,828	224	169	201,962	153,589	8,576	5,477
Total Proved Plus Probable	16,526	13,283	405	307	415,310	320,244	17,584	11,270

Note:

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

Net Present Values of Future Net Revenue

	Before Income Taxes Discounted At (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10% Year[1]	
Reserves Category	**0 ($000s)**	**5 ($000s)**	**10 ($000s)**	**15 ($000s)**	**20 ($000s)**	**0 ($000s)**	**5 ($000s)**	**10 ($000s)**	**15 ($000s)**	**20 ($000s)**	**($/BOE)**	**($/Mcfe)**
Proved Developed Producing	576,951	447,539	369,969	318,154	281,033	574,579	446,965	369,811	318,106	281,018	20.00	3.33
Proved Developed Non–Producing	2,069	1,455	1,069	816	643	1,552	1,280	1,007	793	634	8.38	1.40
Proved Undeveloped	567,611	378,161	265,854	192,681	141,884	425,706	286,032	201,357	145,075	105,352	11.30	1.88
Total Proved	1,146,631	827,154	636,891	511,651	423,561	1,001,838	734,278	572,175	463,974	387,004	15.11	2.52
Probable	1,174,793	696,632	470,039	342,753	262,919	880,969	518,644	346,562	249,909	189,412	13.03	2.17
Total Proved Plus Probable	2,321,425	1,523,786	1,106,930	854,404	686,480	1,882,807	1,252,922	918,737	713,883	576,417	14.15	2.36

Note:

(1) Unit values are based upon net reserves.

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2012
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	2,725,060	549,536	684,226	327,407	17,261	1,146,631	144,794	1,001,838
Proved Plus Probable	5,262,182	1,087,705	1,304,503	524,638	23,912	2,321,425	438,618	1,882,807

FUTURE NET REVENUE
BY PRODUCTION GROUP[(1)]
AS OF DECEMBER 31, 2012
FORECAST PRICES AND COSTS

Reserves Category	Production Group[(1)]	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s)	Unit Value[(2)] Before Income Tax (discounted at 10%/year)
Proved	Light and Medium Crude Oil (including solution gas and other by–products)	291,298	$18.22/BOE
	Heavy Oil (including solution gas and other by-products)	3,093	$22.42/BOE
	Natural Gas (including by–products but excluding solution gas from oil wells)[(3)]	342,500	$13.15/BOE
	Non-conventional oil and gas activities	-	-
	Total	636,891	$15.11/BOE
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by–products)	435,070	$15.69/BOE
	Heavy Oil (including solution gas and other by-products)	6,547	$21.31/BOE
	Natural Gas (including by–products but excluding solution gas from oil wells)[(3)]	665,313	$13.25/BOE
	Non-conventional oil and gas activities	-	-
	Total	1,106,930	$14.15/BOE

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.

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, 2013, which are as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL						
Year	**WTI Cushing Oklahoma ($US/Bbl)**	**Edmonton Par Price 40° API ($Cdn/Bbl)**	**Western Canada Select 20.5° API ($Cdn/Bbl)**	**NATURAL GAS AECO Price ($Cdn/MMBtu)**	**NATURAL GAS LIQUIDS at Edmonton ($Cdn/Bbl)**	**INFLATION RATES(1) %/Year**	**EXCHANGE RATE(2) ($US/$Cdn)**
Forecast							
2013	90.71	85.68	69.73	3.35	94.89	1.83	1.0003
2014	91.64	90.61	75.36	3.80	96.57	1.83	1.0003
2015	92.30	91.60	75.71	4.18	95.97	1.83	1.0003
2016	96.17	95.48	80.23	4.71	100.08	1.83	1.0003
2017	97.29	96.59	80.83	5.12	101.22	1.83	1.0003
2018	98.44	97.71	81.44	5.36	102.41	1.83	1.0003
2019	99.94	99.21	82.49	5.45	104.00	1.83	1.0003
2020	101.76	101.03	83.94	5.57	105.88	1.83	1.0003
2021	103.61	102.88	85.41	5.67	107.82	1.83	1.0003
2022	105.54	104.81	86.91	5.77	109.85	1.83	1.0003
2023	107.46	106.69	88.43	5.87	111.82	1.83	1.0003
2024	109.43	108.65	89.97	5.99	113.85	1.83	1.0003
2025	111.43	110.64	91.54	6.09	115.94	1.83	1.0003
2026	113.48	112.69	93.15	6.19	118.09	1.83	1.0003
2027	115.59	114.76	94.78	6.31	120.26	1.83	1.0003
Thereafter	+ 1.8%/yr	+ 1.8%/yr	+ 1.8%/yr	+ 1.8%/yr	+ 1.8%/yr		

Notes:

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

Weighted average historical prices realized by Bellatrix (before commodity price risk management contracts) for the year ended December 31, 2012, were $2.62/Mcf for natural gas, $86.47/Bbl for light and medium gravity crude oil and condensate, $68.51/Bbl for heavy oil and $38.88/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, 2011 compared to December 31, 2012 based on forecast prices and costs by principal product type:

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
December 31, 2011[(2)]	8,840	5,703	14,543	856	375	1,231
Discoveries	-	-	-	-	-	-
Extensions	1,198	1,055	2,253	-	-	-
Infill Drilling	663	699	1,362	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	670	(1,729)	(1,059)	(73)	61	(13)
Acquisitions	283	283	566	-	-	-
Dispositions	-	-	-	(499)	(212)	(710)
Economic Factors	(105)	47	(57)	-	-	-
Production	(1,082)	-	(1,082)	(103)	-	(103)
December 31, 2012[(3)]	10,468	6,058	16,526	181	224	405

	NATURAL GAS LIQUIDS			NATURAL GAS[(1)]		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
December 31, 2011[(2)]	5,709	3,668	9,377	158,144	95,561	253,705
Discoveries	2	-	3	1,945	421	2,366
Extensions	2,323	3,753	6,075	54,226	86,398	140,624
Infill Drilling	199	147	346	4,433	3,069	7,502
Improved Recovery	-	-	-	-	-	-
Technical Revisions	1,457	415	1,871	16,574	3,739	20,313
Acquisitions	302	627	929	6,799	14,107	20,906
Dispositions	-	-	-	(499)	(154)	(653)
Economic Factors	(77)	(33)	(111)	(4,222)	(1,179)	(5,401)
Production	(905)	-	(905)	(24,052)	-	(24,052)
December 31, 2012[(3)]	9,008	8,576	17,584	213,348	201,962	415,310

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 February 24, 2012 and effective as of December 31, 2011.
(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, 2012, 2011 and 2010 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas[1] (MMcf)		NGLs (Mbbl)	
	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End
Prior thereto	751	751	617	617	9,386	9,386	269	269
2010	3,742	3,742	60	60	23,399	28,090	902	961
2011	2,552	4,425	30	210	49,804	84,812	1,919	3,250
2012	1,124	5,119	0	113	36,227	120,898	1,496	5,200

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas[1] (MMcf)		NGLs (Mbbl)	
	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End
Prior thereto	379	379	293	293	15,776	15,776	440	440
2010	3,600	4,191	90	90	24,025	34,218	933	1,167
2011	2,924	3,458	5	120	46,531	65,527	1,843	2,655
2012	1,620	3,859	0	200	81,223	163,856	4,922	7,003

Note:

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

Proved Undeveloped Reserves

A total of 120,898 MMcf of natural gas, 5,232 Mbbl of oil and 5,200 Mbbl of NGLs were assigned as proved undeveloped reserves as at December 31, 2012, representing approximately 55.4% 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 2013 and 2015 with residual spending until 2021. With respect to capital development costs associated with proved undeveloped reserves in the Sproule Report, approximately 72% of the capital is scheduled to be spent over the next two years and 95% 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 97% 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.

At the time of evaluation, Bellatrix expected the development of its proved undeveloped reserves to be consistent with that set out above. Subsequent to the evaluation date, Bellatrix entered into a joint venture agreement with respect to the Joint Venture, which will affect the development of our undeveloped reserves associated with Bellatrix's interest in the Cardium formation if the Joint Venture closes. The impact of the Joint Venture on Bellatrix's Cardium undeveloped reserves and the associated future net revenue is not reflected in the Sproule Report. The Joint Venture is expected to alter and accelerate the future development schedule of Bellatrix's Cardium undeveloped reserves. See "*Reserves Data – The Effect of the Joint Venture on Reserves Data*". Additionally, 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 163,856 MMcf of natural gas, 4,059 Mbbl of oil and 7,003 Mbbl of NGLs were assigned as gross probable undeveloped reserves in 2012, representing approximately 79.1% of our total probable reserves or 37.0% 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 2013 to 2017. With respect to capital development costs associated with probable undeveloped reserves in the Sproule Report, approximately 48.1% of the capital is scheduled to be spent over the next two years and 82.1% 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.

At the time of evaluation, Bellatrix expected the development of its probable undeveloped reserves to be consistent with that set out above. Subsequent to the evaluation date, Bellatrix entered into a joint venture agreement with respect to the Joint Venture, which will affect the development of our undeveloped reserves associated with Bellatrix's interest in the Cardium formation if the Joint Venture closes. The impact of the Joint Venture on Bellatrix's Cardium undeveloped reserves and the associated future net revenue is not reflected in the Sproule Report. The Joint Venture is expected to alter and accelerate the future development schedule of Bellatrix's Cardium undeveloped reserves. See "*Reserves Data – The Effect of the Joint Venture on Reserves Data*". Additionally, current industry conditions and other uncertainties as indicated under "*Risk Factors*" herein could result in development of Bellatrix's probable reserves on a different schedule than set out above.

Significant Factors or Uncertainties

As discussed under "*General Development of Our Business – Recent Developments*" Bellatrix has entered into a joint venture agreement with respect to a $300 million Cardium Joint Venture in the Ferrier area, which, if the Joint Venture closes, will play a factor in the likely development future development of reserves. As the terms of the Joint Venture were signed after the effective date of the reserve evaluation, and as the Joint Venture has not yet closed, the impact of the Joint Venture was excluded from the reserves evaluation conducted by Sproule. Additionally, 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:

Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2013	109,439	157,773
2014	126,292	172,707
2015	74,032	141,060
2016	17,037	52,438
2017	-	54
Thereafter	605	605
Total: Undiscounted	327,407	524,638

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. Upon closing of the Joint Venture, the capital expenditure program associated with the development of Bellatrix's Cardium undeveloped reserves in the Ferrier area will be altered and accelerated and this impact is not reflected in the estimates of future development costs in the Sproule Report; however, funding the revised program is also expected to be funded from cash flow from operations and available credit facilities. 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. See "*Reserves Data – Effect of the Joint Venture on Reserves Data*".

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, 2012. Unless otherwise indicated, production stated is average daily production for the year ended December 31, 2012 received by Bellatrix in respect of its working interest share before deduction of royalties and without including any royalty interest.

<u>Ferrier</u>

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 7,721 BOE/d in 2012, comprised of 79% natural gas, 11% natural gas liquids and 10% light oil and condensate. The gas is currently processed at third party operated facilities. However, the Corporation has acquired working interests in two major gas processing facilities at Ferrier which is expected to reduce operating expenses and guarantee access to gas markets. Bellatrix's land holdings in the area were 35,130 gross (19,473 net) acres of developed land and 42,772 gross (38,292 net) acres of undeveloped land as at December 31, 2012.

Bellatrix drilled or participated in a total of 17 gross (14.7 net) Cardium oil and liquids-rich gas wells and Notikewin-Falher horizontal liquids-rich gas wells at Ferrier and Alder Flats in 2012, which included 12 gross (12.0 net) Cardium oil and liquids-rich gas wells and 1 gross (1.0 net) liquids-rich Notikewin-Falher gas well operated by the Corporation, and an additional 2 gross (0.7 net) Cardium oil wells and 2 gross (1.0 net) liquids-rich Notikewin-Falher gas wells operated by other parties.

The Corporation reported 100% drilling and completion success in the 13 gross (13.0 net) operated wells that targeted the Cardium and Notikewin-Falher. The 2 gross (1.0 net) non-operated Notikewin-Falher horizontal gas wells were tied-in and placed on production in 2012. The 2 gross (0.7 net) non-operated Cardium horizontal wells that were drilled in 2012 were not completed until the first quarter of 2013.

To date in 2013 at Ferrier, the Corporation has drilled and completed 7 gross (6.6 net) Cardium horizontal wells and the Corporation is currently in the process of drilling 2 gross (2.0 net) additional Cardium horizontal wells. At Alder Flats, Bellatrix has drilled one 100% working interest long-reach, 5,205 metre, Falher horizontal well (2,845 metre lateral section) and a multi-staged fracture stimulation is currently underway. The Corporation is currently drilling 1 gross (0.6 net) operated Falher horizontal well at Alder Flats and is participating in 1 gross (0.5 net) non-operated industry Falher horizontal well that is currently being completed. The Corporation also participated in 2 gross (0.7 net) non-operated Cardium oil wells that were completed and placed on production in January 2013.

The Corporation plans to drill a total of approximately74 gross (74.0 net) Cardium horizontal wells at Ferrier in 2013 as part of the program contemplated by the Joint Venture (assuming the Joint Venture closes). Bellatrix also plans to drill 2 gross (1.0 net) additional Notikewin-Falher tests at Alder Flats in 2013.

Bellatrix has amassed a significant contiguous block of Duvernay rights at Ferrier in 2011 and 2012. Three parcels of lands with Duvernay rights were acquired with a total area of 53 gross (52.6 net) sections. The Corporation has not allocated funds in 2013 for drilling in the Duvernay.

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 and liquids-rich natural gas from zones in the Notikewin, Falher, Ellerslie, and Rock Creek 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 2012 averaged 2,005 BOE/d, consisting of 60% natural gas, 28% light oil and condensate and 12% natural gas liquids. The majority of this production is operated by Bellatrix. Bellatrix held 28,960 gross (16,074 net) acres of developed land and 4,960 gross (2,961 net) acres of undeveloped land in the area as at December 31, 2012.

Bellatrix drilled and completed a total of 2 gross (1.2 net) Cardium oil wells at Willesden Green in 2012. All of the wells were tied in during 2012.

Bellatrix owns interests in and operates three compressor stations in the area. The liquids-rich gas currently produced from this area is processed to pipeline specification at third party plants. Bellatrix has signed an agreement for priority processing at one of the third party gas plants.

To date in 2013, the Corporation has drilled and completed 1 gross (0.5 net) Cardium horizontal oil well.

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 2012, area production averaged 2,382 BOE/d, consisting of 24% natural gas, 72% light oil and condensate, and 4% natural gas liquids. Bellatrix production is processed at third party gas plants. Bellatrix held 28,263 gross (12,662 net) acres of developed land and 9,520 gross (3,737 net) acres of undeveloped land in this area as at December 31, 2012.

Bellatrix drilled of a total of 6 gross (4.7 net) operated Cardium horizontal wells in the Pembina area at Lodgepole, West Pembina and Buck Creek during 2012 with a success rate of 100%, which included 1 gross (0.3 net) Cardium horizontal oil well drilled and completed at Lodgepole, 3 gross (2.7 net) Cardium horizontal oil wells drilled and completed at West Pembina and 2 gross (1.7 net) Cardium horizontal oil wells drilled and completed at Buck Creek.

All 6 gross (4.7 net) Cardium horizontal oil wells drilled in 2012 were completed, tied-in and placed on production in 2012.

Brazeau

The Brazeau area is located approximately 50 kilometres southwest of Drayton Valley, Alberta. Bellatrix's land holdings were 12,000 gross (6,947 net) acres of developed land and 7,840 gross (5,392 net) acres of undeveloped land as at December 31, 2012. In 2012, production averaged 2,829 BOE/d consisting of 57% natural gas, 6% natural gas liquids and 37% light oil and condensate. Principal formations are the Cardium, Viking, Notikewin, Falher and Rock Creek zones at depths of 2,450 metres and 2,700 metres. Production is routed to existing third party facilities in the area for processing.

Bellatrix operated or participated in the drilling of 9 gross (5.7 net) horizontal Cardium oil wells at Brazeau in 2012 including 6 gross (4.7 net) Cardium horizontal tests operated by Bellatrix which were completed and tied-in during 2012. Of the remaining 3 gross (1.0 net) non-operated horizontal Cardium oil wells at Brazeau in 2012, 2 (0.7 net) of the wells were completed in 2012 and one well (0.3 net) was completed in 2013 and all have been tied in.

Bellatrix has participated in the drilling of 2 gross (0.7 net) non-operated horizontal Cardium oil wells to date in 2013. The wells are currently undergoing completion.

Northern Alberta and British Columbia

The Corporation maintains three shallow gas properties in Northern Alberta and British Columbia; however there are no plans for additional development of these properties at this time.

The Saddle Lake and Whitefish Lake properties are located in the vicinity of St. Paul, Alberta, on the Saddle Lake First Nation and the Whitefish Lake First Nation northeast of Edmonton. Bellatrix holds a 50% interest in a joint venture with Keyano Pimee Exploration Corporation Ltd., a corporation that is owned by the Saddle Lake and Whitefish Lake First Nations. The Doris property is located 160 kilometres northwest of Edmonton, Alberta. Bellatrix produces essentially dry shallow gas on these properties.

In 2012, production from the three properties averaged 927 BOE/d with approximately 80% coming from natural gas. The properties account for approximately 5.5% of the Corporation's production base and are considered to be non-strategic in the Corporation's future growth plans.

The Corporation has identified additional drilling and optimization opportunities on the lands but has chosen to defer additional drilling and development until such time that netbacks improve.

South East and Central Alberta and South West Saskatchewan

Bellatrix's properties in South East and Central Alberta and South West Saskatchewan include five producing areas: Rattlesnake, Cypress, Irvine, Faith and Siksika. Rattlesnake is the largest of the five natural gas producing areas and is located approximately 40 kilometres southwest of Medicine Hat. The Second White Specks is one of the key producing horizons in southern Alberta. The Medicine Hat and Milk River formations also significantly contribute to production. In 2012, production averaged 734 BOE/d from predominately shallow natural gas or approximately 4.4% of the Corporation's total production. The Corporation does not anticipate additional development on the properties in 2013.

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, 2012.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	293	221	41	32	364	285	498	374
Saskatchewan	-	-	-	-	15	15	18	18
British Columbia	-	-	-	-	-	-	8	4
Total	293	221	41	32	379	300	524	396

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2012.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	373,705	211,967	194,158	148,815	567,864	360,782
British Columbia	9,752	2,692	107,700	47,521	117,452	50,213
Saskatchewan	13,327	12,720	10,302	10,302	23,628	23,022
Total	396,784	227,380	312,160	206,638	708,944	434,017

Note:

(1) May not add due to rounding.

The following provides details of certain of the Corporation's drilling commitments as at December 31, 2012:

- Bellatrix committed to drill 3 gross (1.7 net) wells pursuant to farm-in agreements as at December 31, 2012. Bellatrix expects to satisfy these drilling commitments at an estimated cost of approximately $6.5 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, 2012, 8 wells remained to be drilled under this commitment for a total estimated cost of $28.0 million.

- Pursuant to a joint venture agreement dated August 4, 2011, Bellatrix is committed to drilling between 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, 2012, 32 wells remained to be drilled under this commitment for a total estimated cost of $112.0 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 all of which are yet to be drilled.

Potentially, approximately 3% of our mineral rights could expire by December 31, 2013 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.

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 67% of total crude oil and natural gas liquids production and an average of 31% of total natural gas production during the twelve months ended December 31, 2012. The following provides details of the commodity price risk management arrangements outstanding as at December 31, 2012 and as of the date hereof.

As at December 31, 2012, the Corporation has entered into commodity price risk management arrangements as follows:

Type	**Period**	**Volume**	**Price Floor**	**Price Ceiling**	**Index**
Crude oil fixed	January 1, 2013 to Dec. 31, 2013	1,500 bbl/d	$94.50 CDN	$94.50 CDN	WTI
Crude oil call option	January 1, 2013 to Dec. 31, 2013	3,000 bbl/d	-	$110.00 US	WTI
Crude oil call option	January 1, 2014 to Dec. 31, 2014	3,000 bbl/d	-	$105.00 US	WTI
Natural gas fixed (1)	April 1, 2013 to Oct. 31, 2013	20,000 GJ/d	$4.0875 CDN	$4.0875 CDN	AECO
Natural gas fixed (2)	April 1, 2013 to Oct. 31, 2013	10,000 GJ/d	$4.15 CDN	$4.15 CDN	AECO

Notes:

(1) Subsequent to year end, the fixed price on this contract was reset to \$3.05/GJ, resulting in cash proceeds of \$4.3 million paid to the Corporation.

(2) Subsequent to year end, the fixed price on this contract was reset to \$3.095/GJ resulting in cash proceeds of \$2.2 million paid to the Corporation.

Subsequent to December 31, 2012, the Company has entered into commodity price risk management arrangements as follows:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Natural gas fixed	April 1, 2013 to June 30, 2014	15,000 GJ/d	\$3.05 CDN	\$3.05 CDN	AECO
Natural gas fixed	Feb. 1, 2013 to Dec. 31, 2013	10,000 GJ/d	\$3.05 CDN	\$3.05 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 \$17.3 million (\$4.4 million discounted at 10%) and \$23.9 million (\$3.6 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)
2013	136	96
2014	81	21
2015	112	64
Subtotal	329	181
Remainder	16,932	23,731
Total (Undiscounted)	17,261	23,912
Total discounted at 10%	4,384	3,585

We currently have 1,030 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, 2012, 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 \$51.6 million, of which \$43.9 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 2012 fiscal year. Depending on production, commodity prices and capital spending levels, management believes that the Corporation will not begin paying current income taxes until 2013 or beyond.

Capital Expenditures

The following table summarizes capital expenditures (excludes non-cash expenditures relating to asset retirement obligations, capitalized unit based compensation and capital leases) related to our assets and activities for the year ended December 31, 2012:

		$000's
Property acquisition costs		
Proved properties		20,966
Undeveloped properties		8,303
Exploration costs		290
Development costs		155,594
Dispositions		(6,660)
Corporate Assets		195
Total	$	178,688

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, 2012.

	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Oil	2	2.0	26	19.3
Natural Gas	1	1.0	5	4.0
Heavy Oil	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	3	3.0	31	23.3

For details on the important current and likely exploration and development activities during 2011, 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, 2013, 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.

Reserves Category	**Light And Medium Oil (Bbls/d)**	**Heavy Oil (Bbls/d)**	**Natural Gas[(1)] (Mcf/d)**	**Natural Gas Liquids (Bbls/d)**	**Total (BOE/d)**
Total Proved	3,211	118	68,910	2,841	17,655
Total Proved Plus Probable	3,636	130	91,827	3,818	22,888

Note:

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

The Ferrier property in the West Central area accounts for 12,790 BOE/d, or 56% 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			
	2012			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production[1]				
Light and Medium Crude Oil (Bbls/d)	3,910	3,672	3,941	4,466
Heavy Oil (Bbls/d)	189	292	368	271
Natural Gas (Mcf/d)[2]	78,195	61,796	64,513	58,660
NGLs (Bbls/d)	1,631	1,240	1,508	1,386
Combined (BOE/d)	18,763	15,503	16,570	15,899
Average Price Received				
Light and Medium Crude Oil ($/Bbl)	82.58	84.98	87.73	90.03
Heavy Oil ($/Bbl)	65.30	63.95	68.40	75.93
Natural Gas ($/Mcf)[2]	3.46	2.45	2.03	2.32
NGLs ($/Bbl) [3]	38.84	28.62	33.59	53.97
Combined ($/BOE)	35.67	33.38	33.35	39.86
Royalties Paid				
Light and Medium Crude Oil ($/Bbl)	19.09	20.80	18.19	15.25
Heavy Oil ($/Bbl)	41.36	31.16	40.01	24.30
Natural Gas ($/Mcf)[2]	0.28	0.12	0.12	(0.32)
NGLs ($/Bbl)	14.87	3.07	21.03	12.09
Combined ($/BOE)	6.86	6.23	7.58	4.57
Operating Expenses				
Light and Medium Crude Oil ($/Bbl)	14.41	11.64	13.93	18.34
Heavy Oil ($/Bbl)	16.47	13.88	14.15	17.09
Natural Gas ($/Mcf)[2]	1.20	1.10	1.14	1.56
NGLs ($/Bbl)	8.54	7.13	8.03	14.89
Combined ($/BOE)	8.91	7.96	8.80	9.20
Netback Received before Transportation				
Light and Medium Crude Oil ($/Bbl)	49.08	52.54	55.61	56.44
Heavy Oil ($/Bbl)	7.47	18.91	14.24	34.54
Natural Gas ($/Mcf)[2]	1.98	1.23	0.77	1.08
NGLs ($/Bbl)	15.43	18.42	4.53	26.99
Combined ($/BOE)	19.90	19.19	16.97	26.09
Transportation Costs				
Light and Medium Crude Oil ($/Bbl)	0.61	1.77	0.52	1.84
Heavy Oil ($/Bbl)	3.39	2.55	2.97	0.94
Natural Gas ($/Mcf)[2]	0.13	0.11	0.09	0.16
NGLs ($/Bbl)	0.01	-	-	0.32
Combined ($/BOE)	0.70	0.90	0.55	1.14
Netback Received after Transportation [4]				
Light and Medium ($/Bbl)	48.47	50.77	55.09	54.60
Heavy Oil ($/Bbl)	4.08	16.36	11.27	33.60
Natural Gas ($/Mcf)[2]	1.85	1.12	0.68	0.92
NGLs ($/Bbl)	15.42	18.42	4.53	26.67
Combined ($/BOE)	19.20	18.29	16.42	24.95

Notes:

(1) Includes minor royalty volumes received but does not deduct royalty volumes paid.
(2) Includes minor amounts of coal bed methane and shale gas production.
(3) NGL pricing excludes pentanes.
(4) 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, 2012. 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	6	-	736	36,618	876	7,721
Brazeau	919	-	116	9,718	174	2,829
Greater Pembina	1,650	-	51	3,489	99	2,382
Willesden Green	442	-	115	7,243	241	2,005
Other Properties	-	-	5	369	22	88
	3,017	-	1,023	57,438	1,412	15,026
Northern Region and British Columbia	1	178	6	4,430	3	927
South East and Central Alberta and South West Saskatchewan	43	-	8	3,945	26	734
TOTALS(1)	3,061	178	1,037	65,812	1,441	16,686

Note:

(1) May not add due to rounding.

Crude oil production from our assets for the year ended December 31, 2012 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, 2012, approximately 60% of gross revenue from our assets was derived from crude oil and natural gas liquids production and 40% 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 (the Common Shares did not commence trading on NYSE MKT until September 24, 2012).

TSX

Period	High ($)	Low ($)	Volume
2012			
January	5.10	4.36	11,429,179
February	5.67	4.66	16,385,652
March	5.64	5.11	13,424,393
April	5.52	3.88	12,309,750
May	4.41	3.25	9,512,513
June	3.70	2.45	10,917,721
July	3.75	2.95	7,664,072
August	3.61	3.13	4,763,921
September	4.26	3.03	7,497,766
October	4.47	3.96	10,542,754
November	4.42	3.86	5,779,070
December	4.36	3.59	4,191,768
2013			
January	5.05	4.03	9,223,482
February	5.75	5.02	6,627,721
March (1 - 14)	6.28	5.20	4,908,002

NYSE MKT

Period	High (US$)	Low (US$)	Volume
2012			
September (24-30)	4.36	3.75	118,004
October	4.54	4.00	785,097
November	4.49	3.85	640,794
December	4.41	3.69	997,004
2013			
January	5.10	4.10	1,121,699
February	5.61	5.00	862,837
March (1 - 14)	6.12	5.04	1,196,579

4.75% Debentures

The 4.75% Debentures are listed for trading on the TSX and trade under the symbol "BXE.DB.A". The following table sets forth the high and low trading prices and trading volume of the 4.75% Debentures on the TSX (with each unit of volume traded being equal to $100 principal amount for each 4.75% Debenture) for the periods indicated.

Period	High ($)	Low ($)	Volume
2012			
January	111.22	104.39	7,490
February	117.50	107.99	14,520
March	117.50	114.20	24,030
April	117.00	103.25	33,245
May	108.44	100.50	43,830
June	103.00	99.00	19,410
July	108.61	100.52	3,260
August	105.86	101.50	2,510
September	106.79	100.00	16,490
October	108.59	104.52	7,970
November	106.50	104.50	2,550
December	105.50	102.73	19,640
2013			
January	110.00	104.50	37,676
February	115.31	109.80	9,470
March (1 - 14)	118.00	110.00	31,510

ESCROWED SECURITIES

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

BORROWINGS

Senior Credit Facilities

As at December 31, 2012 and as at the date hereof, the Corporation's credit facilities consist of a $25 million demand operating facility provided by one Canadian bank and a $195 million extendible revolving term credit facility provided by two Canadian banks and one Canadian financial institution (collectively the "**Credit Facilities**"). The revolving period for the revolving term credit facility will end on June 25, 2013, unless extended for a further 364 day period. Should the facility not be extended it will convert to a non-revolving term facility with the full amount outstanding due 366 days after the last day of the revolving period of June 25, 2013. Amounts borrowed under the Credit Facilities bear interest at a floating rate, with the margin over the Canadian prime rate, U.S. base rate or LIBOR margin rate, and bankers acceptance stamping fee, as applicable being between 1.0% and 3.50%, depending on the type of borrowing and the debt to cash flow 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 against all of the assets of the Corporation by a $400 million debenture containing a first ranking charge and security interest. The Corporation 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 $220 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 redetermination occurring on or before May 31, 2013.

Debentures

On April 20, 2010 the Corporation completed a public offering of 4.75% Debentures by way of short form prospectus for aggregate gross proceeds of $55 million. The 4.75% Debentures have a face value of $1,000 per Debenture and have a maturity date of April 30, 2015 (the "**Maturity Date**"). The payment of the principal and premium, if any, of, and interest on, the 4.75% Debentures is subordinated in right of payment to the prior payment in full of all "Senior Indebtedness" of the Corporation which includes all obligations, liabilities and indebtedness of the Corporation and its subsidiaries which would, in accordance with generally accepted accounting principles be classified as a liability of the Corporation and its subsidiaries, unless it is expressly stated to be subordinated and ranked *pari passu* with the 4.75% Debentures.

The 4.75% Debentures are convertible at the holder's option at any time prior to the close of business on the earlier of the business day immediately preceding the Maturity Date and the date specified by the Corporation for redemption of the 4.75% Debenture into Common Shares at a conversion price of $5.60 per Common Share (the "**Conversion Price**").

The 4.75% Debentures are not redeemable by the Corporation before April 30, 2013. On and after April 30, 2013 and prior to April 30, 2014, the 4.75% Debentures are redeemable at the Corporation's option, in whole or in part, at par plus accrued and unpaid interest if the weighted average trading price of the Common Shares for the specified period is not less than 125% of the Conversion Price. On and after April 30, 2014, the 4.75% Debentures are redeemable at the Corporation's option, in whole or in part, at any time at par plus accrued and unpaid interest.

Upon the maturity or redemption of the Debentures, the Corporation may pay the outstanding principal of and premium (if any) on the Debentures in cash or may, at its option, on not greater than 60 days and not less than 40 days prior notice and subject to regulatory approval, elect to satisfy its obligations to repay all or a portion of the principal amount of the Debentures, together with accrued and unpaid interest thereon, which have matured or been redeemed by issuing and delivering that number of Common Shares obtained by dividing the aggregate principal and premium (if any) on the Debentures which have matured or redeemed by 95% of the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date fixed for redemption or the Maturity Date, as the case may be.

Within 30 days following the occurrence of a "Change of Control" of the Corporation, the Corporation will be required to make an offer (the "**Change of Control Purchase Offer**") in writing to purchase all of the Debentures then outstanding (the "**Debenture Offer**"), at a price equal to 100% of the principal amount thereof plus accrued and unpaid interest thereon. If 90% or more of the aggregate principal amount of the Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered to the Corporation pursuant to the Debenture Offer, the Corporation will have the right to redeem all the remaining Debentures at the same offer price. For this purpose, a Change of Control of the Corporation is deemed to have occurred upon (i) the acquisition by any person, or group of persons acting jointly or in concert (within the meaning of Multilateral Instrument 62-104), of voting control or direction of an aggregate of more than 50% of the outstanding Common Shares; or (ii) the sale of all or substantially all of the assets of the Corporation, but shall not include a sale, merger, reorganization, combination or other similar transaction where the previous holders of Common Shares hold at least 50% of the voting control or direction in such merged, reorganized, combined or other continuing entity (or, in the case of a sale of all or substantially all of the assets, in the entity which has acquired such assets).

In addition, in the event of a Change of Control occurs in which 10% or more of the consideration for the Common Shares in the transaction or transactions constituting the Change of Control consists of cash (other than payment for fractional Common Shares or cash payments made in satisfaction of appraisal rights), equities, securities or other properties not traded or intended to be traded immediately following such transaction on a stock exchange, then during the period beginning 10 trading days after the anticipated date that such Change of Control becomes effective and ending 30 days after the Change of Control Purchase Offer is delivered, holders of the 4.75% Debentures will be entitled to convert the debentures at an adjusted conversion price which will be adjusted based on a formula dependent on the then current trading price and the remaining period up to but excluding April 30, 2014.

The following table summarizes certain terms of the Debentures including the principal amount outstanding as of March 14, 2013:

Maturity Date	Interest Rate at Date of Issue	Principal Amount Outstanding	Conversion Price per Common Share	Number of Common Shares Reserved
April 30, 2015	4.75%	$55,000,000	$5.60	9,821,429

For a complete description of the terms of the 4.75% Debentures, a copy of the 4.75% Debenture Indenture has been filed on www.sedar.com and www.sec.gov under the Corporation's SEDAR and EDGAR profiles, respectively.

DIRECTORS AND OFFICERS

The following table sets forth the name, age (as at December 31, 2012), 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.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director[(1)]	Principal Occupation
Raymond G. Smith, P. Eng. Calgary, Alberta, Canada Age: 65	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., since January 26, 2009, Chairman of Madalena Ventures Inc. since October 2005. Prior thereto, 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

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director[(1)]	Principal Occupation
			Executive Officer of Corsair Exploration Ltd.
Brent A. Eshleman, P. Eng. Calgary, Alberta, Canada Age: 48	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: 57	Vice-President, Finance and Chief Financial Officer	N/A	Vice-President, Finance and Chief Financial Officer of Bellatrix, and prior to November 1, 2009 of True Energy Inc., since July 4, 2006; 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: 64	Vice President and Chief Operating Officer	N/A	Vice-President and Chief Operating Officer of Bellatrix, since October 2010 and prior thereto Vice President, Operations of Bellatrix, and prior to November 1, 2009 of True Energy Inc., 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: 57	Vice-President, Exploration	N/A	Vice-President, Exploration of Bellatrix, and prior to November 1, 2009 of True Energy Inc., 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: 54	Vice President, Land	N/A	Vice President, Land of Bellatrix, and prior to November 1, 2009 of True Energy Inc., since October 2009; prior thereto was Vice President, Land for Terra Energy Corp. from June 2004 to September 2009
Garrett Ulmer Calgary, Alberta, Canada Age: 42	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., since January 2008.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director(1)	Principal Occupation
Duncan Chisholm(6) Calgary, Alberta, Canada Age: 55	Vice-President, Production and Business Development	N/A	Vice-President, Production and Business Development since April 2012 and prior thereto President of KIJJ Investments Ltd. from November 2010 to April 2012. Prior thereto Vice-President Engineering and Chief Operating Officer of Bellatrix, and prior to November 1, 2009 of True Energy Inc., since December 2008. From January 2005 to October 2008 President and Chief Executive Officer of Mahalo Energy Ltd.
W.C. (Mickey) Dunn Calgary, Alberta, Canada Age: 59	Chairman(4)(5)	August 31, 2000	Chairman of Bellatrix and prior to November 1, 2009 of True Energy Inc.; 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: 59	Director(2)(5)	April 26, 2007	Independent businessman. Mr. Baker currently serves as Chair of the Board of Directors of Genesis Land Development Corp. and Chair of the Audit Committee for ATB Financial Ltd., Winstar Resources Ltd., RMP Energy Inc., Longview Oil Corp., and Century Energy Ltd. Served as Chair of the Canadian Institute of Chartered Accountants from October 2008 to 2010.
Murray L. Cobbe Calgary, Alberta, Canada Age: 63	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: 62	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: 82	Director(2)	March 31, 2009	Chairman, Orlick Industries Limited, a private automotive supply company from 1998.
Robert A. Johnson, P.Geol. Calgary, Alberta, Canada Age: 76	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: 56	Director(2)(4)	April 26, 2007	President of Bamako Investment Management Ltd., a private holding and financial consulting company, since July 1994.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director[(1)]	Principal Occupation
Murray B. Todd, B. Sc. P. Eng. **Calgary, Alberta, Canada** **Age: 77**	Director[(3)]	November 2, 2005	President of Canada Hibernia Holding Corporation (an oil and gas production company).

Notes:

(1) Reflects the date of election or appointment as Director of True Energy Inc.
(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) Mr. Chisholm was the President and Chief Executive Officer and a director of Mahalo Energy Ltd. ("**Mahalo**") until October 2008. On May 22, 2009, Mahalo was granted protection from its creditors under the *Companies Creditors Arrangement Act* ("**CCAA**") pursuant to an initial order granted by the Court of Queen's Bench of Alberta. Mahalo concluded a Court approved plan of arrangement to exit CCAA protection on November 12, 2010 that resulted in the cancellation of the existing share capital of the company and the settlement of existing creditor obligations. In addition, also in May 2009, Mahalo's wholly owned subsidiary Mahalo Energy (USA) Inc., a corporation organized under the laws of the State of Delaware filed for and received chapter 11 creditor protection in the United States. On April 20, 2010, the United States chapter 11 proceedings concluded with the transfer of Mahalo USA to Mahalo's creditors. On June 22, 2010, the Alberta Securities Commission issued a cease trade order against Mahalo for failure to file annual financial statements for the year ended December 31, 2009 and for failure to file interim unaudited financial statements for the period ended March 31, 2010. The securities commissions of each of British Columbia, Manitoba, Ontario and Quebec (and together with Alberta, the "**Commissions**") issued similar orders in respect of failure to file financial statements. On November 12, 2010, each of the Commissions issued a full revocation order of the cease trade order and a cease to be reporting issuer order in connection with the conclusion of Mahalo's CCAA proceedings.
(7) 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 March 14, 2013, the directors and officers of Bellatrix, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 2,249,154 Common Shares, representing approximately 2.09% 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:

Name and municipality of residence	Independent	Financially literate	Relevant education and experience
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 Chair of the Board of Directors of Genesis Land Development Corp. and Chair of the Audit Committee for ATB Financial Ltd., Winstar Resources Ltd., 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 Chairman and director of Cirrus Energy Ltd. and a director of Cordy Oilfield Services Inc., Holloman Energy Corp., Madalena Ventures Inc., Mountainview Energy Ltd., Rocky Mountain Dealerships Inc., Stratabound Minerals Inc., Surge Energy Inc. and WCSB Oil & Gas Royalty Income 2010 Management Corp., which is the general partner of WCSB Oil & Gas Royalty Income 2010 Limited Partnership. Mr. MacDonald is a Chartered Accountant.

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, international financial reporting standards, compliance for NYSE MKT listing and due diligence work in respect of financings were $665,550 in 2012 and $351,390 in 2011.

Audit – Related Fees

There were $129,540 in 2012 and $52,530 in 2011 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 2012 or 2011.

All Other Fees

No other professional services fees were billed by the external auditor for other non-audit related fees in 2012 or 2011.

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 and 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. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the 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 primarily determines oil prices. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the 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 current 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) or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can be set by such supply and demand. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective 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, which 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. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/m^3 compared to the previous royalty curve.

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

Oil sands projects are also subject to the 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 and 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, concurrently 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 current royalty regime.

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

The Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, 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.

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

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells between 1,000 and 3,500 metres receive a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. Production from wells operating under the transitional royalty rates will not be subject to the royalty curves for conventional oil and natural gas.

On March 17, 2011, the Government of Alberta approved the *New Well Royalty Regulation* providing for the permanent implementation of a formerly temporary royalty program which provides for a maximum 5% royalty rate for eligible new wells for the first 12 productive months or until the regulated "volume cap" is reached.

In addition to the foregoing, 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 at that time 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, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("**old oil**"), between October 31, 1975 and June 1, 1998 ("**new oil**"), or after June 1, 1998 or through an Enhanced Oil Recovery ("**EOR**") Scheme ("**third-tier oil**"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. 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, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to oil production on Crown land. 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 freehold production tax rate for natural gas liquids is a flat 12.25%.

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

- *Summer Royalty Credit Program* providing a royalty credit equal to 10% of the goods and services costs up to $100,000 for wells drilled between April 1 and November 30 of each year;

- *Deep Royalty Credit Program* providing a royalty credit 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 2,300 metres (or 1,900 metres if spud after August 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs that relate to locations specific factors;

- *Deep Re-Entry Royalty Credit Program* providing 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 subsequent to December 1, 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 m^3 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;

- *Natural Gas Royalty Reduction* providing a reduced royalty on wells drilled on land rights acquired after June 1, 1998 and completed within 5 years of the date the rights are issued;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 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 monthly royalty reductions for low productivity non-conservation natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow non-conservation natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.0 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; 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 m^3 of production, whichever comes first.

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

In August 2012, the Government of British Columbia announced that it is bringing in a nominal 2% royalty on both oil and natural gas on the revenue for the first year of production for wells drilled from September 2012 through to June 2013.

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or 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 conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects) or new oil (oil from wells drilled on or after January 1, 1994). Southwest designated oil uses the same definitions of third and fourth tier oil but 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 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, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

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

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, 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 more than 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties. Natural gas liquids and by-products recovered at gas processing plants are not subject to a royalty. Gas liquids which are produced and measured at the wellhead are treated as crude oil for royalty purposes.

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

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of \$50 per thousand m^3 for third and fourth tier gas and \$35 per thousand m^3 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 **c**ertain differences with respect to the administration of "forth tier gas" which is associated gas.

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

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

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

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

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

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

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

- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery 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 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing Crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR is limited in its carry forward to seven years because of the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards, which are designed to reduce emissions resulting for 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. These will apply to existing licensed wells and facilities on July 1, 2015.

Land Tenure

The respective provincial governments predominantly own 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. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences granted prior to January 1, 2009, but continued after that date, are not subject to shallow rights reversion until they continue past their primary term (at which time the application of deep rights reversion occurs). Afterwards, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements for the satisfactory 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 for pollution damage, and the imposition of material fines and penalties.

On a Federal level and pursuant the Prosperity Act, the Government of Canada amended or appealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime. 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.

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

The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be 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, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into effect on September 1, 2012. The LARP covers approximately 93,212 square kilometres and is in the northeast corner of Alberta. The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82 per cent of the provinces oilsands resource and much of the Cold Lake oilsands area. LARP establishes six new conservation areas, bringing the total conserved land in the region to two million hectares, or 22 per cent—an area three times the size of Banff National Park. The Alberta government plans to pay $30 million to producers whose leases will be cancelled in areas set aside for conservation. Oil and gas companies will be allowed to continue to operate in conservation and recreation areas while oilsands companies' tenures will be cancelled. New petroleum and gas tenure sold in conservation areas will include a restriction that prohibits surface access. Application procedures for activities and facilities in the LARP, regulated by the Energy Resources Conservation Board and the Alberta Utilities Commission, respectively, have been changed to accommodate the new restrictions set out in the LARP. The LARP is the first of seven regions to get a land use plan. The next will be the South Saskatchewan region.

In British Columbia, the *Oil and Gas Activities Act* (the "**OGCA**") impacts conventional oil and gas producers, shale gas producers, and other operators of oil and gas facilities in British Columbia Under the OGCA, the British Columbia Oil and Gas 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 OGCA 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, and 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.

In May of 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 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.

Climate Change Regulation

Federal

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 green house gases ("**GHGs**") and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets. Although the intention was for draft regulations for the implementation of the Updated Action Plan to become binding on January 1, 2010, the only regulations announced pertain to carbon dioxide emissions from coal-fired generation of electricity (finalized in summer 2012). Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent implementation of the proposals contained in the Updated Action Plan will occur.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it would issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline. However, in March 2012, the EPA proposed a strict GHG standard on new power plants only. While it is expected that this rule could encourage building new natural gas power plants rather than coal plants, the actual effect of the new rule will not be able to be quantified for some time.

Alberta

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

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

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

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 CO_2 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 their 2012 Budget, British Columbia announced the government will undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review will cover all aspects of the carbon tax, including revenue neutrality, and will consider the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. Under this comprehensive review, British Columbians can make written submissions to British Columbia's Minister of Finance, and these will be considered as part of the 2013 Budget process.

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 Cap and Trade Act sets out the requirements for the reporting of the greenhouse gas 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 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 further 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. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020.

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.

Risks Relating to the Joint Venture

The Corporation currently expects that the Joint Venture will close on or before April 30, 2012. The Joint Venture may not close for a variety of reasons some of which are not within the control of the Corporation. In addition, even if the Joint Venture closes, the Joint Venture may not close on the terms or the timing currently expected. If the Joint Venture does not close or if completed but the terms or timing are different than expected, it could have an adverse effect on the Corporation's future capital plans and development plans for its properties. Alternatively, the JV Partner may fail to meet its obligations pursuant to the Joint Venture. If any of the events are to occur, the Corporation may be required to seek additional funding, which may or may not be available, to complete the future capital expenditures and development plans it was intending to complete with the financing available as a result of the Joint Venture.

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 are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

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

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and 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 of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA . See "*Directors and Officers – Conflicts of Interest*".

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, 2012 we employed 82 full-time employees (66 are located in the head office and 16 are field employees) and 57 consultants (56 full-time and 1 part-time consultants of which 7 are located in the head office and 50 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, Chartered Accountants, the Corporation's auditors, are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta and within the meaning of the applicable rules and regulations of the SEC and the Public Company Accounting Oversight Board (United States).

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

Bellatrix is not a party to any legal proceeding nor was it a party to any legal proceeding during the 2012 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.

During the year ended December 31, 2012, 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, other than the 4.75% Debenture Indenture.

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 and Debentures. 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 2300, 530 - 8th Avenue S.W.
Calgary, Alberta T2P 3S8
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, 2012 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 15th day of March, 2013.

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

(signed) "*Edward J. Brown*"
Edward J. Brown, C.A.
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, 2012. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2012 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, 2012, 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, 2012, prepared October 2012 to March 2013	Canada	Nil	$1,106,930	Nil	$1,106,930

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 5, 2013

Per: (signed) "*Meghan M. Klein, P. Eng.*"
Petroleum Engineer and Partner

Per: (signed) "*James E. Nemrava, R.E.T.*"
Senior Petroleum Technologist and Partner

Per: (signed) "*Lucia M. Precul, P. Eng.*"
Senior Petroleum Engineer and Partner

Per: (signed) "*George D. Strother-Stewart, P.Geol. on behalf of Alec Kovaltchouk, P.Geo.*"
Manager, Geoscience and Partner

Per: (signed) "*Cameron P. Six, P. Eng.*"
Vice-President, Engineering, Canada 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