TUSCANY ENERGY LTD.

Annual Information Form

Year Ended
December 31, 2014

Date: April 28, 2015

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CERTAIN DEFINITIONS AND CONVENTIONS

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

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

"**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 Tuscany;

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

"**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;

"**McDaniel**" means McDaniel and Associates Consultants Ltd.;

"**McDaniel Report**" has the meaning set forth under "Statement of Reserves Data and Other Oil and Gas Information";

"**net**" means:

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

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

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

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

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

"**Reserves Data**" has the meaning set forth under "*Statement of Reserves Data and Other Oil and Gas Information*";

"**Stock Split**" means the 2 for 1 stock split of the Common Shares effective May 7, 2014;

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

"**Unit**" means a unit of Tuscany comprised of one Common Share and one-half of one Warrant; and

"**Warrant**" means a Common Share purchase warrant of Tuscany, with each whole Warrant entitling the holder thereof to acquire one Common Share at a price of $0.50 until July 17, 2015, provided that if at any time prior to the expiry of the Warrants the 20 day weighted average trading price of the Common Shares on the TSXV is $0.70 or greater, the Warrants will expire 30 days from the date Tuscany gives notice of same to the warrant agent under the indenture governing the Warrants.

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

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

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

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
MBbls	thousand barrels
Bopd	barrels of oil per day
NGLs	natural gas liquids

Natural Gas

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

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
BOEd	barrel of oil equivalent per day
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
M$	thousands of dollars
MM$	Millions 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 Tuscany, the reader should note that the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. 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.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, drilling plans, activities to be undertaken, timing of drilling of wells, tax horizon, timing of development of undeveloped reserves, and planned capital expenditures, the timing thereof and the method of funding, may be forward looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Tuscany's reserves included herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhausted. Additional information on these and other factors that could affect Tuscany'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) and at Tuscany's website (www.tuscanyenergy.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 the Corporation 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 the Corporation'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 the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation 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.

CORPORATE BACKGROUND

Tuscany was incorporated as 630995 Alberta Ltd. under the *Business Corporations Act* (Alberta) on November 7, 1994, and in April 1995 the articles of the Corporation were amended to change the name of the Corporation to "Tuscany Resources Ltd.". In August 1998, the Corporation's articles were further amended to consolidate its outstanding common shares on a five-for-one basis and to change the name of the Corporation to "Tuscany Energy Ltd.". On April 1, 2012, Tuscany amalgamated with its wholly-owned subsidiary, Sharon Energy Ltd. ("**Sharon**"). On July 15, 2013, following Tuscany's acquisition of all of the issued and outstanding shares ("**Diaz Shares**") of Diaz Resources Ltd. ("**Diaz**"), Tuscany's articles were amended to consolidate the Common Shares on an 8 to 1 basis. On January 1, 2014, Tuscany amalgamated with Diaz and continued under the name “Tuscany Energy Ltd.”. On May 7, 2014, the Corporation amended its articles to affect a two for one Stock Split.

The head and principal office of Tuscany is located at Suite 1800, 633 Sixth Avenue S.W., Calgary, Alberta, T2P 2Y5. The registered office of Tuscany is Suite 2400, 525 Eighth Avenue S.W., Calgary, Alberta, T2P 1G1.

DESCRIPTION AND GENERAL DEVELOPMENT OF THE BUSINESS

Tuscany is engaged in the acquisition of, exploration for and development and production of, crude oil and natural gas in Alberta and Saskatchewan, Canada. The following is a brief description of certain events that have influenced the general development of Tuscany's business over the last three completed financial years, which are in addition to the conditions that have affected the oil and gas industry in Western Canada generally.

On June 2, 2011, Tuscany acquired all of the issued and outstanding shares ("**Sharon Shares**") of Sharon pursuant to a plan of arrangement in exchange for approximately 62.1 million Common Shares or 0.84 of a Common Share for each Sharon Share.

On July 15, 2013, Tuscany acquired all of the issued and outstanding Diaz Shares pursuant to a plan of arrangement in exchange for approximately 29.3 million Common Shares or 0.31 of a Common Share for each Diaz Share, following which the Common Shares were consolidated on an 8 to 1 basis.

On December 10, 2013, the Corporation issued 1,282,051 Common Shares on a flow-through basis at a price of $0.39 per share for aggregate consideration of $500,000.

On July 17, 2014, Tuscany issued an aggregate of 4,286,000 Units and 3,214,000 Common Shares on a flow-through basis at prices of $0.40 per Unit and $0.40 per Common Share for aggregate gross proceeds of $3 million.

On November 19, 2014, the Corporation issued 1,318,000 Common Shares on a flow-through basis at a price of $0.44 per share for aggregate consideration of $579,920.

On November 26, 2014, the Corporation issued 1,412,000 Common Shares on a flow-through basis at a price of $0.44 per share for aggregate consideration of $621,280.

On December 10, 2014, the Corporation issued 2.28 million Common Shares on a flow-through basis at a price of $0.44 per share for aggregate consideration of $1,003,200.

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 April 28, 2015. The effective date of the Statement is December 31, 2014 and the preparation date of the Statement is February 24, 2015.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by McDaniel with an effective date of December 31, 2014 (the "**McDaniel Report**"). The Reserves Data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue attributable to these reserves using forecast prices and costs. The Reserves Data conforms with the requirements of NI 51-101. We engaged McDaniel to provide an evaluation of proved and proved plus probable reserves. No attempt was made to evaluate possible reserves. All of the Corporation's reserves are in Canada in the provinces of Alberta 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 net present value 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. Further, the recovery and reserve estimates of the crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
DECEMBER 31, 2014
FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
RESERVES CATEGORY	Gross (MBbls)	Net (MBbls)	Gross (MBbls)	Net (MBbls)	Gross (MMcf)	Net (MMcf)	Gross (MBbl)	Net (MBbls)
PROVED								
Producing	42.3	36.4	681.9	655.5	920.1	858.9	1.3	0.9
Non-producing	-	-	116.5	114.6	-	-	-	-
Undeveloped	-	-	599.6	581.8	-	-	-	-
TOTAL PROVED	42.3	36.4	1,398.0	1,351.9	920.1	858.9	1.3	0.9
PROBABLE	11.5	9.7	1,219.6	1,150.0	209.7	196.7	0.3	0.2
TOTAL PROVED PLUS PROBABLE	53.8	46.1	2,617.6	2,501.9	1,129.8	1,055.6	1.6	1.1

	NET PRESENT VALUES OF FUTURE NET REVENUE									
	BEFORE INCOME TAXES DISCOUNTED At (% per year)					AFTER INCOME TAXES DISCOUNTED AT (% per year)				
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)	0 (MM$)	5 (MM$)	10 (MM$)	15 (MM$)	20 (MM$)
PROVED										
Producing	19.87	18.33	16.99	15.78	14.75	19.87	18.33	16.96	15.78	14.75
Non-producing	3.74	2.96	2.39	1.97	1.65	3.74	2.96	2.39	1.97	1.65
Undeveloped	18.00	14.31	11.47	9.27	7.54	17.98	14.29	11.46	9.26	7.53
TOTAL PROVED	41.61	35.60	30.85	27.01	23.94	41.59	35.59	30.82	27.01	23.93
PROBABLE	52.12	39.76	31.09	24.83	20.20	38.96	29.47	22.89	18.19	14.75
TOTAL PROVED PLUS PROBABLE	93.73	75.36	61.91	51.84	44.14	80.55	65.06	53.70	45.20	38.68

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
DECEMBER 31, 2014
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOP-MENT COSTS (M$)	WELL ABANDON-MENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
PROVED	107,027	5,676	40,725	14,368	4,647	41,611	17	41,594
PROBABLE	99,254	7,220	24,404	14,902	611	52,117	13,161	38,956
TOTAL PROVED PLUS PROBABLE	206,281	12,896	65,129	29,270	5,258	93,728	13,178	80,550

FUTURE NET REVENUE
BY PRODUCTION GROUP
DECEMBER 31, 2014
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% per year) (M$)	UNIT VALUE BEFORE INCOME TAXES (discounted at 10% per year)
PROVED	Light and Medium Crude Oil (including solution gas and other by-products)	888.0	$ 24.40 /Bbl
	Heavy Oil (including solution gas and other by-products)	32,193.0	$ 23.81 /Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	(2,256.0)	$ (2.63) /Mcf
	Total	30,825.0	$ 20.13 /BOE
PROVED PLUS PROBABLE	Light and Medium Crude Oil (including solution gas and other by-products)	1,162.0	$ 25.21 /Bbl
	Heavy Oil (Including solution gas and other by-products)	63,069.0	$ 25.21 /Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	(2,321.0)	$ (2.20) /Mcf
	Total	61,910.0	$ 22.73 /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.

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 McDaniel 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.

(b) **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.

(c) **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.

(d) **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 McDaniel 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 a stand-alone basis utilizing the Corporation's tax pools. 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 McDaniel in the McDaniel Report were McDaniel's forecast as at January 1, 2015 and are as follows:

SUMMARY OF PRICING AND INFLATION AND EXCHANGE RATE ASSUMPTIONS
December 31, 2014
FORECAST PRICES AND COSTS

			OIL			NATURAL GAS		NGLs		
			WTI Cushing	Edmonton Light	Bow River Hardisty	AECO spot	NYMEX	Edmonton Par Price		
YEAR	Inflation Rate	Exchange Rate	Oklahoma ($US/bbl)	Par Price ($Cdn/bbl)	Par Price ($Cdn/bbl)	Gas Price ($Cdn/Mcf)	Gas Price ($US/Mcf)	Propane ($Cdn/bbl)	Butane ($Cdn/bbl)	Condensate ($Cdn/bbl)
2015	2.0%	0.860	65.00	68.60	58.30	3.50	3.30	26.10	52.80	72.60
2016	2.0%	0.860	75.00	83.20	70.70	4.00	3.80	36.50	67.00	87.30
2017	2.0%	0.860	80.00	88.90	75.60	4.25	4.05	44.50	71.60	93.10
2018	2.0%	0.860	84.90	94.60	80.40	4.50	4.30	49.30	76.20	98.80
2019	2.0%	0.860	89.30	99.60	84.70	4.70	4.55	51.80	80.30	103.90
2020	2.0%	0.860	93.80	104.70	89.00	5.00	4.85	54.70	84.40	109.10
2021	2.0%	0.860	95.70	106.90	90.90	5.30	5.10	56.20	86.10	111.40
2022	2.0%	0.860	97.60	109.00	92.70	5.50	5.30	57.50	87.89	113.60
2023	2.0%	0.860	99.60	111.20	94.50	5.70	5.50	58.90	89.60	115.90
2024	2.0%	0.860	101.60	113.50	96.50	5.90	5.70	60.30	91.50	118.30
2025	2.0%	0.860	103.60	115.70	98.30	6.00	5.80	61.50	93.20	120.60
2026	2.0%	0.860	105.70	118.00	100.30	6.10	5.90	62.70	95.10	123.00
2027	2.0%	0.860	107.80	120.40	102.30	6.25	6.05	64.00	97.00	125.50
2028	2.0%	0.860	110.00	122.80	104.40	6.35	6.15	65.20	99.00	128.00
2029	2.0%	0.860	112.20	125.30	106.50	6.50	6.30	66.60	101.00	130.60
After	+2%/yr	0.095	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

Weighted average historical prices realized by Tuscany for the year ended December 31, 2014, were $4.30/Mcf for natural gas and $73.2/Bbl for heavy oil.

Reconciliation of Changes in Reserves

The following table sets out the reconciliation of our gross reserves as at December 31, 2013 compared to December 31, 2014 based on forecast prices and costs by principal product type:

RECONCILIATION OF COMPANY GROSS RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL			NATURAL GAS LIQUIDS			ASSOCIATED AND NON-ASSOCIATED GAS		
FACTORS	Proved (MBbl)	Probable (MBbl)	Proved Plus Probable (MBbl)	Proved (MBbl)	Probable (MBbl)	Proved Plus Probable (MBbl)	Proved (MBbl)	Probable (MBbl)	Proved Plus Probable (MBbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2013[1]	20.7	3.5	24.2	1,080.1	882.2	1,962.3	1.7	0.3	2.0	1,333.9	255.9	1,589.8
Production	(13.5)	-	(13.5)	(211.7)	-	(211.7)	(0.4)	-	(0.4)	(311.0)	-	(311.0)
Technical revisions	35.1	8.0	43.1	152.6	(169.6)	(17.0)	-	-	-	(169.8)	(64.2)	(234.0)
Extensions and improved recovery	-	-	-	345.0	498.0	843.0	-	-	-			-
Discoveries	-	-	-	32.0	9.0	41.0	-	-	-			-
Acquisitions			-			-	-	-	-	67.0	18.0	85.0
December 31, 2014[2]	42.3	11.5	53.8	1,398.0	1,219.6	2,617.6	1.3	0.3	1.6	920.1	209.7	1,129.8

Notes:

(1) As evaluated by McDaniel in a report dated February 19, 2014 and effective as of December 31, 2013.
(2) As evaluated in the McDaniel Report.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved Undeveloped Reserves

Proved undeveloped reserves are those proved reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Tuscany's proved undeveloped heavy oil reserves at December 31, 2014 were assigned to 8 wells (4.8 net wells) to be drilled in the Evesham area, 9 wells (9 net wells) to be drilled in the Macklin area and 2 wells (1.25 net wells) to be drilled in the Lloydminster area. The program will require capital expenditures to develop proved undeveloped reserves of approximately $426,700 in 2015, and $9.1million in 2016.

The following tables set forth the proved undeveloped gross reserves, by product type, attributed to our assets for the most recent three years and, in the aggregate, before that time based on forecast prices and costs.

	Heavy OIL (MBbl)		NATURAL GAS (MMcf)		NGL's (MBbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto		143.8	-	-	-	-
2012	129.2	273.0	-	-	-	-
2013	175.9	448.9	-	-	-	-
2014	150.7	599.6	-	-	-	-

Probable Undeveloped Reserves

Probable undeveloped reserves are those probable reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Tuscany's probable undeveloped heavy oil reserves at December 31, 2014 were assigned to 3 wells (1.8 net wells) to be drilled in the Evesham area, 8 wells (8 net wells) to be drilled in the Macklin area and 4 wells (2 net wells) to be drilled in the Lloydminster area. The program will require capital expenditures to develop probable undeveloped reserves of approximately $847,900 in 2015, and $9.2 million in 2016.

The following tables set forth the probable undeveloped gross reserves, by product type, attributed to our assets for the most recent three years and, in the aggregate, before that time based on forecast prices and costs.

	HEAVY OIL (MBbl)		NATURAL GAS (MMcf)		NGL's (MBbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior thereto	-	81.4	-	-	-	-
2012	300.6	382.0	-	-	-	-
2013	251.5	633.5	-	-	-	-
2014	586.1	1,219.6	-	-	-	-

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

Significant Factors or Uncertainties

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

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Corporation does not anticipate any significant abandonment costs and reclamation costs, unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Future Development Costs

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

	FORECAST PRICES & COSTS	
	Proved Reserves	Proved Plus Probable Reserves
Year	(MM$)	(MM$)
2015	426.7	847.9
2016	9,210.7	9,210.7
2017	4,730.7	10,054.3
2018	-	9,156.7
2019	-	-
Thereafter	-	-
TOTAL UNDISCOUNTED	14,368.1	29,269.6

The Corporation expects that the estimated development costs set forth in the preceding table will be funded through internally generated cash flows and, as required, available credit facilities and the proceeds of equity and/or debt financings. Any financing costs relating to funding the estimated future development costs would reduce future net revenue attributable to those reserves but Tuscany does not expect that such financing costs would make the development of the properties uneconomic. There can be no guarantee that funds will be available or that the board of directors of Tuscany will allocate funding to develop most of the reserves in the McDaniel Report. Failure to develop those reserves would have a negative impact on future net revenues. The current plan, which is incorporated into the reserves analysis, is to focus on developing Tuscany's heavy oilfields near Evesham and Macklin, Saskatchewan. Certain capital expenditures may be delayed from time to time as the Corporation's capital requirements are prioritized in an effort to maximize future cash flow and return on investment.

Other Oil and Gas Information

Principal Properties

The following is a description of Tuscany's principal oil and natural gas properties as at December 31, 2014. Unless otherwise indicated, production stated is average gross production for the periods specified and gross and net acres and well information is as at December 31, 2014. **Reserve information is as evaluated by McDaniel in the McDaniel Report. 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.**

Macklin, Saskatchewan – 100% Working Interest

In the Macklin area Tuscany has a 100% working interest in 15 producing Dina heavy oil wells and 2 wells which are shut in pending the completion of facilities to connect the wells to water handling systems owned by Tuscany. In 2014 Tuscany drilled 5 new horizontal heavy oil wells on the property. To date Tuscany has produced over 334 MBbls from the property and production averaged 452 Bopd for the month of February 2015. Tuscany's 2014 production at Macklin, primarily from the Dina oil pool, averaged 345 BOEd. This is compared with average production of 189 BOEd in 2013.

Management expects that when oil prices have returned to an acceptable level the Macklin Dina oil pool will be a focus of the Company's development program.

The following table summarizes the gross reserves to Tuscany, assigned to the Macklin area by the McDaniel Report.

Macklin	**Natural Gas**		**Oil**	
Reserves				
Proved developed producing	63	MMcf	379	MBbl
Proved developed non-producing	-	MMcf	62	MBbl
Proved undeveloped	-	MMcf	365	MBbl
Probable	20	MMcf	770	MBbl
Total proved plus probable	83	MMcf	1,576	MBbl
Q4 2014 average production			452	Bopd

Macklin Proved plus Probable reserves totalled 1,590 MBOE, (55.6% of Total Company Reserves)

Evesham, Saskatchewan – 60% Working Interest

Tuscany has a 100% working interest in 9 producing horizontal heavy oil wells at its Macklin Tuscany has a 60% working interest in 13 producing Dina heavy oil wells (7.8 net wells) and 3 wells (1.8 net wells) which are shut in pending the development of infrastructure to connect the wells to water handling facilities. Tuscany also has a 100% working interest in 3 producing Sparky oil wells and a gas well providing fuel gas to the property. The field has three water disposal wells which are connected to the wells in the north half of the field by pipeline. During 2014 Tuscany drilled 2 horizontal heavy oil wells (1.2 net wells) on the property. By the end of February 2015 Tuscany had produced more than 487 MBbls of oil from the Evesham Dina pool and the 13 producing wells were still producing at a rate of 336 Bopd.

2014 production at Evesham, primarily from the Dina oil pool, averaged 376 BOEd (239 BOEd net). This is compared with average production of 294 BOEd (199 BOEd net) in 2013.

Management expects that when oil prices have returned to an acceptable level the Evesham Dina oil pool will be a focus of the Company's development drilling program.

The following table summarizes the gross reserves, assigned to Tuscany's interest, assigned to the Evesham area by the McDaniel Report.

Evesham	Natural Gas		Oil	
Reserves				
Proved developed producing	107	MMcf	268	MBbl
Proved developed non-producing	-	MMcf	54	MBbl
Proved undeveloped	-	MMcf	204	MBbl
Probable	22	MMcf	372	MBbl
Total proved plus probable	129	MMcf	898	MBbl
Q4 2014 average production			305	Bopd

Evesham Proved plus Probable reserves totalled 920 MBOE, (32.1% of Total Company Reserve

Oil and Natural Gas Wells

The following table sets forth the number and status of oil wells and gas wells in which we had a working interest as at December 31, 2014.

	OIL WELLS				NATURAL GAS WELLS			
	Producing		Non-Producing		Producing		Non-Producing	
LOCATION	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	33	9.5	4	1	99	40.7	44	17.6
Saskachewan	54	37.0	8	8	1	1.0	1	0.5
Total	87	46.5	12	9.0	100	41.7	45	18.1

Properties with No Attributed Reserves

The following table sets out our undeveloped land holdings as at December 31, 2014.

	UNDEVELOPED ACRES	
LOCATION	Gross	Net
Alberta	118,741	46,630
Saskatchewan	18,880	18,670
Total	137,621	65,300

Development of Tuscany's 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, access to infrastructure and availability and reliability of methods of hydrocarbon delivery.

The Corporation expects that rights to explore, develop and exploit approximately 8,991 net acres of its undeveloped land holdings will expire by December 31, 2015, a portion of which may be continued by drilling. Tuscany plans to drill or submit applications to continue selected portions of the above acreage.

Forward Contracts and Marketing

Tuscany's net share of oil and gas production is sold to marketing companies and other third party purchasers at the oil terminal or sales gas pipeline**,** with the exception of small amounts of product which are marketed by the well operators. At December 31, 2014, the Corporation had no outstanding fixed physical sales or other forward contracts.

Additional Information Concerning Abandonment and Reclamation Costs

Well abandonment and disconnect costs were estimated and included in the McDaniel Report at the individual entity level for all wells. 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 reclamation costs for wells and facility abandonment and reclamation expenses have not been included in the McDaniel Report.

In the McDaniel 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 future well abandonment costs, all of which is deducted in the calculation of future net revenue, is $4.6 million ($2.2 million discounted at 10%) in the case of proved reserves and $5.3 million ($2.3 million discounted at 10%) in the case of proved plus probable reserves. In the next three financial years, these costs are as follows:

Year	Proved ($M)	Proved Plus Probable ($M)
2015	-	0
2016	31	31
2017	534	534
	565	565
Remainder	4,082	4,693
Total undiscounted	4,647	5,258
Total discounted at 10%	2,229	2,256

At December 31, 2014 Tuscany currently has 225 wells (125 net wells) for which we expect to incur abandonment and reclamation costs. At December 31, 2014, the estimated total undiscounted amount required to settle the asset retirement obligations (being abandonment and reclamation costs for net producing and shut in wells, leases, pipelines and facilities) of the Corporation was approximately

$7.5 million. The present value of the obligation discounted using risk free rates of 1.34% to 2.33%, of $5.1 million has been recognized in the Corporations financial statements.

Tax Horizon

Based on the forecasted production, revenue and capital expenditures used in the McDaniel Report for total proved plus probable reserves, before consideration of the deduction of future administrative expenses, McDaniel estimates Tuscany will be taxable on its Canadian income in 2017.

Capital Expenditures

The following table summarizes capital expenditures related to Tuscany's assets and activities for the year ended December 31, 2014:

Capital expenditures	(M$)
Land, net of disposals	692
Exploration costs	67
Development costs	10,575
TOTAL	11,334

Exploration and Development Activities

The following table summarizes the number of development and disposal wells in which Tuscany had an interest that were drilled during the year ended December 31, 2014. Tuscany did not participate in the drilling of any exploration or dry wells during 2014.

Development Wells	Gross	Net
Heavy Oil	9	7.46
Disposal well	1	1.00
TOTAL - Development	10	8.46
TOTAL WELLS	10	8.46

Production Estimates

Total Company

The following table sets out the volume of our gross production estimated for the year ended December 31, 2015, which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*" above.

Reserve category	Crude Oil (Bopd)	Natural Gas (Mcfd)	NGL's (Bopd)
Total Proved	603.3	657.3	1.5
Probable	53.7	7.9	0.5
Proved plus probable	657.0	665.2	2.0

Evesham, Saskatchewan

The following table sets forth the volume of gross production from our Evesham property estimated for the year ended December 31, 2015, which accounts for greater than 20% of our total estimated production:

Reserve category	Crude Oil (Bopd)	Natural Gas (Mcfd)	NGL's (Bopd)
Total Proved	192.9	59.7	-
Probable	11.8	0.8	-
Proved plus probable	204.7	60.5	-

Macklin, Saskatchewan

The following table sets forth the volume of gross production from our Macklin property estimated for the year ended December 31, 2015, which accounts for greater than 20% of our total estimated production:

Reserve category	Crude Oil (Bopd)	Natural Gas (Mcfd)	NGL's (Bopd)
Total Proved	358.4	37.0	-
Probable	39.5	0.5	-
Proved plus probable	397.9	37.5	-

Production History

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

	QUARTER ENDED 2014			
	Mar. 31	Jun. 30	Sept. 30	Dec. 31
Production [1]				
Heavy Oil (Bopd) Evesham	210.2	202.7	204.7	295.2
Heavy Oil (Bopd) Macklin	299.1	362.5	262.3	450.6
Heavy Oil (Bopd) Other	44.5	36.7	35.5	30.6
Heavy Oil (Bopd) Total	553.8	601.9	502.5	776.4
Natural Gas (Mcfd) Evesham	89.1	55.9	51.6	57.0
Natural Gas (Mcfd) Other	642.9	875.6	856.8	777.6
Natural Gas (Mcfd) Total	732.0	931.5	908.4	834.6
Combined corporate total (BOEd)	675.8	757.1	653.9	915.5
Average Price Received				
Heavy Oil ($/bbl)	74.18	82.67	78.17	61.95
Natural Gas ($/mcf)	5.65	4.47	3.84	3.40
Combined ($/BOE)	66.90	71.22	65.41	55.64
Royalties Paid				
Heavy Oil ($/bbl)	3.67	4.69	5.45	4.63
Natural Gas ($/mcf)	0.88	0.75	0.42	0.51
Combined ($/BOE)	3.96	4.66	4.77	4.39
Operating Expenses				
Heavy Oil ($/bbl)	20.61	15.79	19.97	15.86
Natural Gas ($/mcf)	3.35	3.65	4.21	5.48
Combined ($/BOE)	20.52	17.04	21.19	18.45
Netback Received [2]				
Heavy Oil ($/bbl)	49.90	62.19	52.75	41.46
Natural Gas ($/mcf)	1.42	0.07	(0.79)	(2.59)
Combined ($/BOE)	42.42	49.52	39.45	32.80

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating costs from revenues.

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 to 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 "Risk Factors".

HUMAN RESOURCES

At December 31, 2014, Tuscany directly employed 13 staff and various consultants, all of which were based at its office in Calgary.

DIVIDEND POLICY

The Corporation has not paid any dividends on its outstanding shares and does not intend to in the foreseeable future. The future payment of dividends will be dependent upon the financial requirements of the Corporation to fund future growth, the financial condition of the Corporation and other factors the board of directors of the Corporation may consider appropriate in the circumstances. Pursuant to Tuscany's current credit facility, Tuscany is restricted from paying dividends or redeeming or repurchasing any of its outstanding shares except for a normal course issuer bid of up to 5% of its issued and outstanding shares, without the written consent of its lender.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized share capital of Tuscany consists of an unlimited number of Common Shares. The holders of Common Shares are entitled to: (i) one vote per share at meetings of Tuscany shareholders, (ii) dividends if, as and when declared by the board of directors on the Common Shares, and (iii) upon liquidation, dissolution or winding-up of Tuscany, to receive the remaining property of Tuscany.

MARKET FOR SECURITIES

The Common Shares are listed for trading on the TSXV under the symbol "TUS". The following table sets forth the price range and trading volume of such shares on the TSXV (as reported by the TSXV) for each month during the last completed financial year.

Common Share Trading Data- Year ended December 31, 2014

Month	High	Low	Volume
January	0.19	0.16	173,382
February	0.20	0.17	68,495
March	0.24	0.20	131,441
April	0.27	0.21	1,121,759
May	0.46	0.26	549,474
June	0.46	0.30	1,110,728
July	0.46	0.36	432,781
August	0.52	0.37	2,205,204
September	0.74	0.46	1,746,019
October	0.55	0.37	1,263,719
November	0.45	0.35	431,118
December	0.37	0.22	715,088

Note:

(1) The Common Shares began trading on the TSXV on a post-Stock Split basis on May 8, 2014. The information is presented on a post-Split basis.

PRIOR SALES

Other than as set forth below, the Corporation did not issue any securities during the financial year ended December 31, 2014 that were not listed or quoted on a marketplace:

1. on July 17, 2014, an aggregate of 2,143,000 Warrants were issued in connection with Tuscany's public offering of Units and flow-through Common Shares (see "*Description and General Development of the Business*").

2. effective March 31, 2014, an aggregate of 650,000 options to acquire an equal number of Common Shares (or 1,310,000 Common Shares after giving effect to the Stock Split) at a price of $0.445 per Common Share ($0.2225 per Common Share after giving effect to the Stock Split) were granted; and

3. an aggregate of 1,250,000 options to acquire an equal number of Common Shares (or 2,500,000 Common Shares after giving effect to the Stock Split) at a price of $0.37 per Common Share ($0.185 per Common Share after giving effect to the Stock Split) were granted on February 24, 2014.

DIRECTORS AND OFFICERS

The names, jurisdiction of residence, positions with Tuscany, principal occupations and the period served as a director of Tuscany are set out below. The term of office of each director of the Corporation expires at the next annual meeting of shareholders.

Name and Municipality of Residence	Office Held	Principal Occupation For Past Five Years
Robert W. Lamond(1)(2) Alberta, Canada	Chairman of the Board, President and Chief Executive Officer; director since October 16, 2001	Chairman of the Board and President and Chief Executive Officer of the Corporation and Humboldt Capital Corporation ("**Humboldt**"), a TSXV listed investment company.
Donald K. Clark Alberta, Canada	Vice-President, Operations and Chief Operating Officer; director since October 16, 2001	Vice President, Operations and Chief Operating Officer of the Corporation and Vice-President of Operations of Humboldt.
Roger Hume(1)(3) B.C., Canada	Director Since March 30, 2010	Independent Businessman
Robert L. (Locke)(3) McPherson Alberta, Canada	Director since July 15, 2013	Independent Businessman
John R. Nelson Alberta, Canada	Director since July 15, 2013	President and Chief Executive Officer of Africa Hydrocarbons Inc., a TSX Venture Exchange listed oil and gas company, since March 1, 2012; prior thereto, President and Chief Executive Officer of Lion Energy Corp., a public oil and gas company, from 2009 to 2011.
Glen A. Phillips(1)(3) Alberta, Canada	Director since October 7, 2009	Independent Businessman
Charles A. Teare(2) Alberta, Canada	Director since March 11, 1994	Executive Vice President and Chief Financial Officer of the Corporation and Humboldt.
C. Steven Cohen Alberta, Canada	Corporate Secretary	Partner with Burnet, Duckworth & Palmer LLP (Barristers & Solicitors)

Notes:

(1) Member of the Compensation Committee.
(2) Each of Messrs. Lamond and Teare was a director of Trafina Energy Ltd. prior to a receiver being appointed by the Court of Queen's Bench of Alberta in June 2012 to hold its assets. Messrs. Lamond and Teare resigned from the board on the date the receiver was appointed.
(3) Member of Audit Committee.

As at April 28, 2015, the directors and executive officers of the Corporation as a group beneficially owned, or controlled or directed, directly or indirectly, 17,647,766 Common Shares, representing approximately 34.6% of the outstanding Common Shares.

Corporate Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than as set forth above, to the knowledge of the Corporation, no director or executive officer of the Corporation is, as of the date hereof, or was within ten years before the date hereof, a director, chief executive officer or chief financial officer of any company (including the Corporation), that: (a) was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an

“Order”), that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (b) was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Other than as set forth above, to the knowledge of the Corporation, no director, executive officer or a shareholder holding a sufficient number of Common Shares to affect materially the control of Tuscany: (a) is, as of the date hereof, or has been within the ten years before the date hereof, a director or executive officer of any company (including the Corporation) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (b) has, within the ten years before the date hereof, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

To the knowledge of the Corporation, no director or executive officer of the Corporation or a shareholder holding a sufficient number of Common Shares to affect materially the control of Tuscany, has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable shareholder in deciding whether to vote for a proposed director.

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 and should not 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 its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

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

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

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

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

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

Prices, Markets and Marketing

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

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

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

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

Reserve Estimates

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

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

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

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

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized in the Corporation’s Statement of Reserves Data and Other Oil and Gas Information for the year ended December 31, 2014. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

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

Diluent Supply

Heavy oil is characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport heavy oil to market and correspondingly increasing the Corporation's overall operating cost, decreasing its net revenues and negatively impacting the overall profitability of its heavy oil projects.

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.

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. Accordingly, the price at which the Common Shares of the Corporation will trade cannot be accurately predicted.

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 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 in accordance with applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

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.

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.

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.

Regulatory

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

Royalty Regimes

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

Competition

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

Cost of New Technologies

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

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites.

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

Liability Management

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

Climate Change

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

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

Additional Funding Requirements

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

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

Credit Facility Arrangements

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

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. A material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the

Corporation under the credit facility. This 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.

Title to Assets

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

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

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

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.

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.

Alternatives to and Changing Demand for Petroleum Products

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

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.

Income Taxes

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

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

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. In addition, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Corporation.

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.

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.

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 to 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.

Breach of Confidentiality

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

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.

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering and processing facilities and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities and pipeline systems. The lack of availability of capacity in any of the gathering and processing facilities 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 have a material adverse effect on the Corporation's ability to process its production and deliver the same for sale.

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.

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.

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.

INDUSTRY CONDITIONS

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

Pricing and Marketing

Oil

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

Natural Gas

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

The North American Free Trade Agreement

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

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

Royalties and Incentives

General

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

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

Saskatchewan

In Saskatchewan, taxes (“**Resource Surcharge**”) and royalties are applicable to revenue generated by corporations focused on oil and gas operations.

A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act*. For resource corporations, the Resource Surcharge rate is 3% of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. The Resource Surcharge applies to resource trusts in addition to resource corporations.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses and applications in the oil and gas sector by eliminating 11 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company's production and number of wells. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Government of Saskatchewan to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

Alberta

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

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

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

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

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

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

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months 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 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.

Land Tenure

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

Each of the provinces of Alberta, British Columbia, and Saskatchewan have 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.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, we must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

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

Federal

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

Saskatchewan

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

Alberta

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

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

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

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

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

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP overs approximately 83,764 square kilometres and includes 44% of the provincial population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. Similar to LARP, the SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

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

Liability Management Rating Programs

Saskatchewan

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

Alberta

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

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

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and

- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

These changes will be implemented over a three-year period. The first phase was implemented in May of 2013, the second phase was implemented in May of 2014 and the final phase was to be implemented in May of 2015 but has been delayed until August 1, 2015. The changes to the LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On July 4, 2014, the AER introduced the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within 5 years. As of April 1, 2015, each licensee will be required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*.

Climate Change Regulation

Federal

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

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

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

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. The MRGGA establishes a framework for achieving the provincial target of a 20% reduction in GHG emissions from 2006 levels by 2020. Although the MRGGA and related regulations have yet to be proclaimed in force, draft versions indicate that Saskatchewan will permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to the federal climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

Alberta

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

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

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

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2

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

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

LEGAL PROCEEDINGS

Since the beginning of the most recently completed financial year: (i) there have been no material legal proceedings to which the Corporation is or was a party or of which any of its properties is or was the subject matter, nor are there any such proceedings known to the Corporation to be contemplated; (ii) no penalties or sanctions have been imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (iii) no other penalties or sanctions have been 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; and (iv) no settlement agreements have been entered into by the Corporation before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of any directors or executive officers of the Corporation, any shareholder 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 of the Corporation or during the current financial year which has materially affected, or would reasonably be expected to materially affect, the Corporation other than the following.

On July 15, 2013, Tuscany acquired all of the issued and outstanding Diaz Shares in exchange for Common Shares on the basis of 0.31 of a Common Share for each share of Diaz (the "**Acquisition**"). At the time, Mr. Lamond, the Chairman, President and Chief Executive Officer of Tuscany, and Humboldt, a company controlled by Mr. Lamond, beneficially owned or controlled approximately 71.2 million Diaz Shares, representing approximately 75.3% of the outstanding Diaz Shares. Accordingly, Mr. Lamond and Humboldt received approximately 22.1 million Common Shares pursuant to the Acquisition (approximately 5.52 million Common Shares after giving effect to the subsequent 8:1 share consolidation and 1:2 Stock Split), representing approximately 15% of the outstanding Common Shares.

Tuscany and Humboldt have an arrangement whereby they manage and share overhead costs on the basis of: (i) the estimated time spent by their shared employees (including executive officers) on matters involving each company; and (ii) the estimated amount of office space used by each company.

TRANSFER AGENT AND REGISTRAR●●●

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the Corporation has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year that are still in effect except as follows:

Credit facility

At December 31, 2014, the Corporation had a production loan facility (the "**Credit Facility**") with a Canadian financial institution, with a lending limit of $8.5 million, $4.0 million of which was drawn. The Credit Facility is repayable on demand and subject to a borrowing base redetermination performed on a periodic basis by the lender based on the lenders view of the Corporation's reserves and future commodity prices. The next review is required to be completed by May 31, 2015. Pursuant to the Credit Facility, the Corporation has a financial covenant to maintain a Working Capital Ratio of at least 1 to 1, with Working Capital Ratio being defined to mean the ratio of (i) current assets of the Corporation plus any undrawn amount under the Credit Facility, to (ii) current liabilities of the Corporation less (to the extent included therein) any amount drawn under the Credit Facility. At December 31, 2014, the Corporation's Working Capital Ratio was 1.1 to 1 and the Corporation is in compliance with the covenant. The facility is a revolving facility with advances under the facility charged interest at prime plus 1.4% per annum. The loan is secured by a general security agreement providing a security interest over all present and after acquired property and a floating charge on all land.

INTERESTS OF EXPERTS

KPMG LLP has prepared the auditor's report on the consolidated financial statements of the Corporation for the year ended December 31, 2014. KPMG LLP has advised Tuscany that they are independent with respect to the Corporation within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

McDaniel prepared the McDaniel Report evaluating Tuscany's oil and gas reserves effective December 31, 2014. To the knowledge of the Corporation, no registered or beneficial interests, direct or indirect, in any securities or other property of Tuscany or its associates or affiliates (i) were held by McDaniel or any of its designated professionals (as such term is defined in Form 51-102F2) when the McDaniel Report was prepared; (ii) were received by McDaniel or any of its designated professionals after the preparation of the McDaniel Report; or (iii) are to be received by McDaniel or any of its designated professionals.

No 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.

ADDITIONAL INFORMATION

Additional information relating to the Corporation may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for its most recent annual meeting of shareholders. Additional financial information is contained in the Corporation's consolidated financial statements for the year ended December 31, 2014 and the related management's discussion and analysis.

SCHEDULE "A"

Form 51-101 F3
Report of Management and Directors on Oil and Gas Disclosure

Management of Tuscany Energy 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 and probable oil and gas reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

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

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 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 approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

DATED: April 28, 2015

(Signed) "R.W. Lamond"
President and Chief Executive Officer

(Signed) "C.A. Teare"
Executive Vice President & CFO

(Signed) "D.K. Clark"
Director

(Signed) "R. L. McPherson"
Director

SCHEDULE "B"

McDaniel & Associates Consultants Ltd.

February 24, 2015

Tuscany Energy Ltd.
1800, 633 – 6th Avenue SW
Calgary, Alberta
T2P 2Y5

Attention: The Board of Directors of Tuscany Energy Ltd.

Re: **Form 51-101F2**
Report on Reserves Data by an Independent Qualified Reserves Evaluator of Tuscany Energy Ltd. (the "Company")

To the Board of Directors of Tuscany Energy Ltd. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014 estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2014, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate) Audited	Evaluated	Reviewed	Total
February 24, 2015	Canada	-	61,910	-	61,910

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 report referred to in paragraph 4 for events and circumstances occurring after the preparation date.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

P. A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta
February 24, 2015