TUSCANY ENERGY LTD.

Annual Information Form

Year Ended
December 31, 2010

Report Date

April 18, 2011

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ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrels
Bopd	barrels of oil per day
BOE	barrels of oil or natural gas and crude oil on the basis of 1 Bbl of crude oil for 6 Mcf of natural gas (and not based on current prices)
BOEd	BOE per day
MBbl	thousand barrels
Mstb	thousand stock tank barrels
Mstbe	thousand stock tank barrels equivalent
NGLs	Natural Gas Liquids
MBOE	Thousand BOE

Natural Gas

Mcfe	thousand cubic feet of gas equivalent (oil is equated to natural gas on the basis of 1 barrel = 6 Mcf)
Mcf	thousand cubic feet
MMbtu	million British thermal units
MMcf	million cubic feet
Bcf	billion cubic feet
GJd	gigajoule per day
Mcfd	thousand cubic feet per day
MMcfd	million cubic feet per day
psia	pounds per square inch absolute

Other

M$	thousands of dollars
MM$	millions of dollars
3D	three dimensional
AFE	authorization for expenditure
API	American Petroleum Institute
ARTC	Alberta Royalty Tax Credit
Cdn.	Canadian
NRI	net revenue interest
OPEC	Organization of the Petroleum Exporting Countries
W.I.	working interest

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

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.

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 in various areas, timing of drilling, recompletion and tie-in of wells, tax horizon, timing of development of undeveloped reserves, 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 provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could effect 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.Tuscanyrenergy.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.

BACKGROUND

Tuscany Energy Ltd. ("**Tuscany**" or the "**Corporation**") was incorporated as 630995 Alberta Ltd. under the Business Corporations Act (Alberta) on November 7, 1994, and on April 7, 1995 changed the name of the Corporation to Tuscany Resources Ltd.

At its shareholders' meeting on August 11, 1998, the Corporation's shareholders approved an amendment to the Articles of the Corporation to consolidate the number of the outstanding common shares of the Corporation ("**Common Shares**"), on a five-for-one basis and the name of the Corporation was changed to Tuscany Energy Ltd.

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 1400, 350 Seventh Avenue S.W., Calgary, Alberta, T2P 3N9.

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 Western Canada.

On November 16, 2010 Tuscany issued 8,000,000 common shares of Tuscany at a price of $0.15 per share for gross proceeds of $1,200,000.

On October 7, 2009, Tuscany and Goldmark Minerals Ltd. ("Goldmark") obtained a final order from the Court of Queen's Bench of Alberta approving the plan of arrangement (the "Arrangement") pursuant to which Tuscany acquired all of the issued and outstanding shares of Goldmark. Tuscany issued, in aggregate, approximately 12.2 million common shares of Tuscany ("Tuscany Shares") to shareholders of Goldmark based on an exchange ratio of 0.6 Tuscany Shares for each Goldmark Share.

On October 1, 2009 Tuscany issued 8,685,635 common shares of Tuscany at a price of $0.06 per share for gross proceeds of $521,138.

On October 18, 2007 Tuscany raised $1,000,000, through the issuance of 10,000,000 Common Shares at $0.10 per share.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Tuscany is engaged in the acquisition of, exploration for and development and production of, crude oil and natural gas in Western Canada. Tuscany's focus during 2009 and 2010 has been the development of a Dina heavy oil pool on its lands at Evesham, Saskatchewan. Tuscany has drilled 5 horizontal oil wells on the property. The Corporation believes the property has significant development potential and during 2011 plans to focus its capital expenditures on developing this pool.

During 2010 Tuscany began to work with two related partners and to acquire and develop its oil and gas properties. In 2010, Tuscany began a new joint venture arrangement with Sharon Energy Ltd. ("Sharon") and Diaz Resources Ltd. ("Diaz") collectively (the "Group"). The details of the joint venture arrangement are:

- Diaz employees provide management, administrative and technical support for the Group;

- The Group shares the use of assets necessary to conduct their business including, but not limited to, office space, computer hardware, computer software, technical data and furniture and equipment;

- The operations related to oil and gas exploration, development and operating activities by the Group is conducted by employees of Diaz;

- Overhead costs are shared in an equitable manner within the Group based on a number of factors including, time spent by employees on each of the companies; proportionate share of capital expenditures and revenues of the companies in the Group and the ratio of each of the companies in new acquisitions of oil and gas leases.

- Working interests in new acquisitions of oil and gas leases or properties are acquired in a ratio to be determined from time to time in accordance with the financial capabilities of the three companies. The ratio currently set was determined at January 1, 2010 as, Diaz 45%, Tuscany 30% and Sharon 25%.

Since the beginning of this relationship Tuscany has acquired interest in 15,110 gross acres (4,533 net acres) of prospective lands in Alberta and Saskatchewan.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The effective date of the statement of reserves data and other oil and gas information set forth below (the "Statement") is December 31, 2010 and the preparation date of the Statement is April 18, 2011.

Disclosure of Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by McDaniel & Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2010, contained in a report of McDaniel dated February 9, 2011 (the "McDaniel Report"). The Reserves Data summarize the oil, liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Data conforms to the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional information not required by NI 51-101 has been presented to provide continuity and information which we believe is important to the readers of this information. The Corporation engaged McDaniel to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Corporation's reserves are in the provinces of Alberta and Saskatchewan in Canada.

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

The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached as Schedule "A" and Schedule "B" hereto, respectively.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS

	RESERVES (1)									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL	TOTAL
RESERVES CATEGORY	Gross (2) (MBbl)	Net (3) (MBbl)	Gross (2) (MBbl)	Net (3) (MBbl)	Gross (2) (MMcf)	Net (3) (MMcf)	Gross (2) (MBbl)	Net (3) (MBbl)	Gross (2) (MBOE)	Net (3) (MBOE)
PROVED										
Developed Producing	4.0	3.3	302.3	289.1	517.7	508.8	0.6	0.3	393.2	377.5
Developed Non-producing	-	-	15.0	14.3	-	-	-	-	15.0	14.3
Undeveloped	-	-	270.0	264.1	-	-	-	-	270.0	264.1
TOTAL PROVED	4.0	3.3	587.3	567.5	517.7	508.8	0.6	0.3	678.2	655.9
PROBABLE	10.0	9.1	448.9	416.7	83.1	81.3	0.2	0.1	473.0	439.5
TOTAL PROVED PLUS PROBABLE (1)	14.0	12.4	1,036.2	984.2	600.7	590.0	0.7	0.4	1,151.0	1,095.3

(1) Columns may not add due to rounding.
(2) Gross reserves are the Corporation's working interest share, before deduction of royalties and with out including any royalty interest.
(3) Net reserves are the Corporation's working interest share, after deduction of royalties plus the Corporation's royalty interest in reserves.

	NET PRESENT VALUES OF FUTURE NET REVENUE (1)									
	BEFORE INCOME TAXES DISCOUNTED AT (% per year)					AFTER INCOME TAXES DISCOUNTED AT (% per year)				
	0	5	10	15	20	0	5	10	15	20
RESERVES CATEGORY	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
PROVED										
Developed Producing	11.95	10.03	8.64	7.62	6.85	11.95	10.03	8.64	7.64	6.85
Developed Non-producing	0.35	0.32	0.29	0.26	0.24	0.35	0.32	0.29	0.26	0.24
Undeveloped	6.07	4.90	3.97	3.24	2.66	5.24	4.25	3.45	2.81	2.30
TOTAL PROVED	18.37	15.25	12.91	11.13	9.75	17.55	14.60	12.39	10.71	9.39
PROBABLE	18.51	13.19	9.97	7.89	6.48	13.64	9.62	7.18	5.62	4.55

Additional Information Concerning Future Net Revenue (Future Prices and Costs)

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2010
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	45,540	1,500	19,028	5,336	1,304	18,372	823	17,548
PROVED PLUS PROBABLE	81,480	3,924	30,793	8,355	1,526	36,882	5,693	31,190

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10% per year) (M$)	Percent of Total (%)	UNIT Values (1) BEFORE INCOME TAXES (discounted at 10% per year)	
PROVED	Light and Medium Crude Oil (including solution gas and other by-products)	17	0%	$ 5.13	/Bbl
	Heavy Oil (including solution gas and other by-products)	12,937	100%	$ 22.80	/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	(47)	0%	$ (5.80)	/Mcf
	Total	12,907			
PROVED PLUS PROBABLE	Light and Medium Crude Oil (including solution gas and other by-products)	242	1%	$ 19.47	/Bbl
	Heavy Oil (Including solution gas and other by-products)	22,678	99%	$ 23.04	/Bbl
	Natural Gas (including by-products but excluding solution gas from oil wells)	(44)	0%	$ (4.42)	/Mcf
	Total	22,876			

Note 1 - Unit values are calculated using the 10% discount rate divided by the Major Product Type Net reserves for each group.

Definitions and Other Notes

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "Gross" means:

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

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

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

2. "Net" means:

   (a) in relation to the Corporation's interest in production and reserves the Corporation's working interest (operating and non-operating) share after deduction of royalties obligations, plus the Corporation's royalty interest in production or reserves;

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

   (c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

3. "Exploration well" means a well that is not a development well, a service well or a stratigraphic test well.

4. "Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

   (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

   (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

5. "Development well" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

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

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

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

8. Definitions used for reserve categories are as follows:

Reserve Categories

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

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions (see the discussion of "Economic Assumptions" below).

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

(d) 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.

(e) 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 be met for the categorization of reserves are provided in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook").

(f) "Economic Assumptions" will be the forecast prices and costs used in the estimate.

Development and Production Status

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

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

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

(ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

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

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves

are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(c) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(d) 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.

9. Forecast prices and costs

Future prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table under "Pricing Assumptions" identifies benchmark reference pricing that applies to the Corporation.

10. Future income tax expenses estimate (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes;

(b) without deducting estimated future costs that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances; and

(d) applying to the future pre-tax net cash flows relating to the Corporation's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

11. Estimated future abandonment and reclamation costs related to a property have been taken into account by McDaniel in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom.

12. The forecast price and cost assumptions assumed the continuance of current laws and regulations.

13. The extended character of all factual data supplied to McDaniel was accepted by McDaniel as represented. No field inspection was conducted.

14. Numbers in tables may not add due to rounding.

Pricing Assumptions

The following sets for the benchmark reference prices, as at December 31, 2010, reflected in the Reserves Data. These price assumptions were provided to the Corporation by McDaniel, the Corporation's independent qualified evaluator.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS

YEAR	Inflation Rate	Exchange Rate	WTI Crude Oil $US/bbl	Edmonton Light Crude Oil $Cdn/bbl	Alberta Bow River Hardisty Crude Oil $Cdn/bbl	Alberta Heavy Crude Oil $Cdn/bbl	Alberta AECO Gas Price $Cdn/Mcf	U.S. Henry Hub Gas Price $US/Mcf	Alberta Average Plantgate $Cdn/MMBtu	Sask. Spot Sales Plantgate $Cdn/MMBtu
Historical										
2010	2.0%	0.971	79.40	77.45	68.40	62.30	4.15	4.35	3.90	4.20
Forecast										
2011	2.0%	0.975	85.00	84.20	72.80	66.70	4.25	4.55	4.05	4.15
2012	2.0%	0.975	87.70	88.40	75.00	68.70	4.90	5.30	4.70	4.80
2013	2.0%	0.975	90.50	91.80	75.10	68.60	5.40	5.75	5.20	5.30
2014	2.0%	0.975	93.40	94.80	77.50	70.80	5.90	6.30	5.70	5.80
2015	2.0%	0.975	96.30	97.70	80.00	73.00	6.35	6.80	6.15	6.25
2016	2.0%	0.975	99.40	100.90	82.50	75.40	6.75	7.35	6.55	6.65
2017	2.0%	0.975	101.40	102.90	84.20	76.90	7.10	7.70	6.85	6.95
2018	2.0%	0.975	103.40	104.90	85.90	78.40	7.40	8.00	7.15	7.25
2019	2.0%	0.975	105.40	107.00	87.50	80.00	7.60	8.20	7.35	7.45
2020	2.0%	0.975	107.60	109.20	89.30	81.60	7.75	8.35	7.50	7.60
2021	2.0%	0.975	109.70	111.30	91.10	83.20	7.85	8.50	7.60	7.70
2022	2.0%	0.975	111.90	113.60	92.90	84.90	8.05	8.70	7.80	7.90
2023	2.0%	0.975	114.10	115.80	94.70	86.60	8.20	8.85	7.95	8.10
2024	2.0%	0.975	116.40	118.10	96.70	88.30	8.40	9.05	8.15	8.30
2025	2.0%	0.975	118.80	120.60	98.60	90.10	8.50	9.20	8.25	8.40
2026+	2.0%	0.975	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr

Weighted average prices (excluding fixed natural gas contracts) realized by the Corporation for the year ended December 31, 2010, in Canada, were $4.02 per Mcf for natural gas, $38.40 a Bbl for NGLs and $61.90 a Bbl for heavy oil.

Reconciliation of Changes in Gross Reserves

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

	LIGHT AND MEDIUM CRUDE OIL			HEAVY CRUDE OIL			NATURAL GAS LIQUIDS			ASSOCIATED AND NON-ASSOCIATED GAS			EQUIVALENT BOEs (MBOEs)		
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)	Proved (MBOE)	Probable (MBOE)	Proved Plus Probable (MBOE)
December 31, 2009	11.4	2.3	13.7	374.4	237.7	612.1	0.6	-	0.6	551.5	133.7	685.2	478.4	262.3	740.6
Production	(2.0)		(2.0)	(44.5)		(44.5)	-		-	(58.0)		(58.0)	(56.2)	-	(56.2)
Technical revisions	(5.4)	(1.1)	(6.5)	56.1	(10.0)	46.1		0.1	0.1	24.2	(50.6)	(26.5)	54.7	(19.3)	35.3
Extensions	-	-	-	180.0	210.0	390.0	-	-	-	-	-	-	180.0	210.0	390.0
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Acquisitions	-	8.8	8.8	21.3	11.2	32.5	-	-	-	-	-	-	21.3	20.0	41.3
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Economic factors	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2010	4.0	10.0	14.0	587.3	448.9	1,036.2	0.6	0.1	0.7	517.7	83.1	600.7	678.2	473.0	1,151.0

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved Undeveloped Reserves

Proved undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Tuscany's proved undeveloped reserves consist primarily of 9 (5.4 net) horizontal drilling locations at Evesham, all within 100 metres of existing wells. Reserves have been assigned based on geological mapping. To the extent that reserves are not expected to be economically drained through existing production wells and infill drilling is economically feasible, proved reserves have been assigned to these undrilled spacing units.

In order to develop these reserves, Tuscany plans to drill the wells in its principal Canadian Heavy Oil property of Evesham Saskatchewan over the next two years. This program will require capital expenditures of approximately $4.7 million in 2011 and $0.6 million in 2012 to develop the proved undeveloped reserves and a further $2.9 million in 2012 to develop the probable undeveloped reserves. The timing of the program is also dependent upon working interest partners in the area, who may or may not agree with the plans of Tuscany.

PROVED UNDEVELOPED RESERVES

AS OF DECEMBER 31, 2010

PROVED UNDEVELOPED RESERVES

	Heavy OIL (MBbl)	
	First Attributed	Cumulative at Year End
Prior thereto	-	-
2009	60	60
2010	210	270

PROBABLE UNDEVELOPED OIL AND GAS RESERVES
AS OF DECEMBER 31, 2010

PROBABLE UNDEVELOPED RESERVES

	HEAVY OIL (MBbl)	
	First Attributed	Cumulative at Year End
Prior thereto	-	-
2009	135	135
2010	210	345

Probable Undeveloped Reserves

Probable undeveloped reserves are those reserves which are to be recovered from known accumulations where a significant expenditure is required to render them capable of production; however, these reserves are less certain to be recovered. Reserves have been assigned based on geological mapping, To the extent that reserves are not expected to be economically drained through existing production wells and infill drilling is economically feasible and that the certainties of recovering additional reserves does not meet the proved threshold, probable undeveloped reserves have been assigned. Tuscany's probable undeveloped reserves include horizontal drilling locations adjacent to proved undeveloped locations at Evesham.

Significant Factors or Uncertainties

Proved and probable undeveloped reserves require significant expenditures of capital to render them capable of production. The Corporation may not have access to such capital. See “Risk Factors –

Availability under Credit Facility" There is also significant risk that service or equipment may not be available at the time required and this may change the forecast of production.

The estimate of the net present value of future net revenue attributable to the Corporation's reserves, as set forth in the McDaniel Report and summarized herein, is based on McDaniel's forecast of prices and costs as at December 31, 2010, and was therefore determined at a point in time and will not necessarily represent prices and costs or estimates of future prices and costs as at other points in time. The net present value of future net revenue does not represent fair market value. See "Risk Factors – Reserve Estimates"

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Corporation's future net revenue attributable to the reserve categories noted below.

	FORECAST PRICES & COSTS	
	Proved Reserves	Proved Plus Probable Reserves
Year	(M$)	(M$)
2011	$ 4,743	$ 4,797
2012	$ 593	$ 3,558
TOTAL UNDISCOUNTED	$ 5,336	$ 8,355
Total Discounted at 10%	$ 3,009	$ 4,592

Tuscany plans to finance the above capital expenditures using internally generated cash flow and equity or debt financing as required and if available on acceptable terms. 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 Evesham heavy oilfield in 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, 2010 (unless otherwise indicated). Production stated is average gross production for the periods indicated unless otherwise stated. Gross and net acres and well information is as at December 31, 2010, unless otherwise specified. **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 competence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation**.

In Canada, during the year ended December 31, 2010, 4 wells were drilled (net 2.15) resulting in four oil wells (net 2.15).

Evesham, Saskatchewan Dina Pool – Working Interest 60%

Tuscany has a 60% working interest in 5 (3.0 net) producing Dina heavy oil wells. The Evesham is area located approximately 100 kilometers south of Lloydminster, Saskatchewan east of the Alberta border. The Evesham Dina pool was the primary development focus of the Corporation for 2010. The Corporation plans eight additional horizontal wells into the Dina pool in 2010.

Evesham, Saskatchewan Dina	Heavy Oil	Natural Gas
Reserves		
Proved developed producing	118 MBbl	- MMcf
Proved developed non-producing	- MBbl	- MMcf
Proved undeveloped	270 MBbl	- MMcf
Probable	410 MBbl	- MMcf
Total proved plus probable	798 MBbl	- MMcf
2010 average production	56 Bopd	- Mcfd

The Evesham Dina pool represents 69% of the Corporation's Reserves at December 31, 2010.

Tuscany requested McDaniel prepare a Contingent Resource report on the Dina oil pool on Tuscany's lands and McDaniel concluded that 59 additional wells could be drilled on the property.

The McDaniel Report has identified 9 proved in-fill locations and 5 probable locations adjacent to the five existing wells. MCDANIEL forecasts initial production rates of approximately 85 Bopd per well. The McDaniel Report assigns 75 MBbls of proved plus probable reserves (45 MBbls net) to each of the the 14 undrilled locations.

Evesham and Macklin, Saskatchewan Sparky Pool – Working Interest 100%

Tuscany has a 100% working interest in 10 producing Sparky oil wells (9.2 net wells) at Evesham and the nearby Macklin areas. In addition to the Dina production discussed above, Tuscany's production in the Evesham and Macklin areas is currently from low productivity oil wells completed in the Sparky sand. Production from these wells represented 29% of the Corporation's production in 2010. Tuscany plans to continue to maintain the production from these areas through required workovers and technological improvements in production methods on the basis of prioritized capital expenditures.

Evesham, Saskatchewan Sparky	Oil and NGLs	Natural Gas
Reserves		
Proved developed producing	130 MBbl	412 MMcf
Proved developed non-producing	- MBbl	- MMcf
Proved undeveloped	- MBbl	- MMcf
Probable	21 MBbl	63 MMcf
Total proved plus probable	150 MBbl	475 MMcf
2010 average production	38 Bopd	- Mcfd

Macklin, Saskatchewan	Oil and NGLs	Natural Gas
Reserves		
Proved developed producing	55 MBbl	87 MMcf
Proved developed non-producing	15 MBbl	- MMcf
Proved undeveloped	- MBbl	- MMcf
Probable	19 MBbl	15 MMcf
Total proved plus probable	88 MBbl	102 MMcf
2010 average production	17 Bopd	107 Mcfd

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest as at December 31, 2010.

	OIL WELLS				NATURAL GAS WELLS			
	Producing		Non-Producing		Producing		Non-Producing	
LOCATION	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Saskatchewan	13	12.6	11	10.1	-	-	-	-
Alberta	1	0.3	-	-	3	0.6	3	0.6
Total	14	12.9	11	10.1	3	0.6	3	0.6

Properties with no Attributable Reserves

The following table sets out the Corporation's undeveloped land holdings as at December 31, 2010:

	UNDEVELOPED ACRES		Net Acres Expiring
LOCATION	Gross	Net	Within One Year
Alberta	7,147	3,128	74
Saskatchewan	14,418	4,575	1,584
Total	21,565	7,703	1,658

There are no work commitments on the undeveloped acreage as at December 31, 2010.

Marketing and Forward Contracts

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.

Where appropriate, in the opinion of management, the Corporation will sell products forward or use other derivative transactions to fix the price of its product or the exchange rate. During the year ended December 31, 2010, no forward sales agreements were entered into.

Additional Information Concerning Abandonment and Reclamation Costs

The Corporation estimates the cost to abandon wells and the cost to reclaim the leases and facility sites based on costs incurred in the areas for similar wells. Salvage costs of equipment which will be removed from the site are also based on estimates currently available for such equipment. Such costs are escalated to the expected date of abandonment at an inflation rate estimate of 2%.

At December 31, 2010, Tuscany had an interest in 44 wells (31.14 net wells) for which it would be responsible for the costs to abandon in the future. The Corporation's share of the estimated abandonment cost is estimated to be $1.2 million and the present value of this amount, discounted at 10%, is $0.7 million. Tuscany estimates that $20,000 of abandonment costs will be incurred over the next three years, having a present value of $18,000 at a 10% discounted rate.

The McDaniel Report considers only the cost of abandoning wells with respect to the future net reserves estimated. In addition The McDaniel Report includes the cost estimates for abandoning undrilled wells. The abandonment costs in the McDaniel Report were estimated to be $1.5 million in total with a present value of $0.4 million at a 10% discount rate.

Tax Horizon

Based on the forecast production, revenue and capital expenditures used in the McDaniel Report for total proved reserves, and Tuscany's estimate of overhead and interest expense, Tuscany will commence paying tax on its Canadian income in 2013.

Capital Expenditures

The following table summarizes capital expenditures (net of incentives and ARO reductions) related to the Corporation's activities for the year ended December 31, 2010:

Capital expenditures		Total (M$)
Exploration costs	$	490
Development costs		1,629
Land acquisition		254
Equipment		670
TOTAL	$	3,043

Exploration and Development Activities

During 2010, Tuscany participated in drilling activities as follows.

Exploration Wells	Gross	Net
Oil	1	0.35
Natural Gas	-	-
Dry and abandoned		
TOTAL - Exploration	1	0.35
Development Wells		
Oil	3	1.80
Natural Gas	-	-
Dry and abandoned	-	-
TOTAL - Development	3	1.80
TOTAL WELLS	4	2.15

Production Estimates

The following table sets out the volume of the Corporation's production, before royalties, estimated for the year ended December 31, 2011 which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "Disclosure of Reserves Data".

TOTAL COMPANY	Light and Medium Oil (Bopd)	Heavy Oil (Bopd)	Natural Gas (Mcfd)	Natural Gas Liquids (Bopd)	BOE (BOEd)
Proved developed producing	3.6	160.3	180.0	0.5	194.4
Proved developed non-producing	-	11.0	-	-	11.0
Proved undeveloped	-	148.2	22.5	1.7	153.7
Total Proved	31.4	140.4	307.7	2.2	359.1
Probable	2.2	35.0	12.3	0.3	39.6
Proved plus probable	33.7	150.7	321.8	2.4	398.7

Production from the Evesham property which is more than 20% of the estimated 2011 production is as follows:

EVESHAM, SASKATCHEWAN	Light and Medium Oil (Bopd)	Heavy Oil (Bopd)	Natural Gas (Mcfd)	Natural Gas Liquids (Bopd)	BOE (BOEd)
Proved developed producing	-	138.1	144.9	-	162.3
Proved developed non-producing	-	-	-	-	-
Proved undeveloped	-	151.2	-	-	151.2
Total Proved	-	110.2	109.0	-	313.5
Probable	-	34.5	1.6	-	34.8
Proved plus probable	-	119.4	111.2	-	348.3

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback on a unit of production basis for the periods indicated below for the significant areas and the Corporation as a whole:

	QUARTER ENDED 2010			
	Dec. 31	Sept. 30	June 30	Mar. 31
Production [(1)]				
Heavy Oil (Bopd) Evesham	105.8	98.1	74.6	98.5
Heavy Oil (Bopd) Company Total	122.2	111.7	98.9	107.0
Light/medium Oil & NGLs (Bopd) Company Total	4.4	6.2	5.5	11.7
Natural Gas (Mcfd) Evesham	120.9	108.0	72.9	126.1
Natural Gas (Mcfd) Company Total	128.1	207.8	120.7	200.1
Company (BOEd)	147.9	152.6	124.5	152.0
Average Price Received				
Heavy Oil ($/bbl)	58.65	52.38	67.40	71.29
Light/medium Oil & NGLs ($/bbl)	62.19	55.75	54.44	62.68
Natural Gas ($/mcf)	4.58	2.72	3.82	4.72
Combined ($/BOE)	54.26	44.34	59.65	61.20
Royalties Paid				
Heavy Oil ($/bbl)	2.76	2.96	2.79	4.43
Light/medium Oil & NGLs ($/bbl)	10.88	13.76	14.23	23.14
Natural Gas ($/mcf)	0.36	0.28	0.22	0.34
Combined ($/BOE)	2.92	3.11	3.05	5.34
Operating Expenses				
Heavy Oil ($/bbl)	33.28	32.16	25.60	35.25
Light/medium Oil & NGLs ($/bbl)	9.01	34.25	64.65	32.59
Natural Gas ($/mcf)	5.05	2.06	4.31	1.59
Combined ($/BOE)	32.13	27.76	27.36	29.41
Netback Received [(2)]				
Heavy Oil ($/bbl)	22.61	17.26	39.01	31.61
Light/medium Oil & NGLs ($/bbl)	42.30	7.74	(24.44)	6.95
Natural Gas ($/mcf)	(0.83)	0.38	(0.71)	2.79
Combined ($/BOE)	19.21	13.47	29.24	26.45

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

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, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada,

Alberta, and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the 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 and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through the liquid market hubs such as the Alberta Nova Inventory Transfer ("NIT") hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain 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 and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

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

Pipeline Capacity

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production levels of oil and natural gas in western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. 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 prohibits discriminatory border restrictions and export taxes. NAFTA also 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.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of 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, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

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

Alberta

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

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty

curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010. Alberta royalties in effect after December 31, 2010 are known as the "Alberta Royalty Framework" ("**ARF**").

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the ARF, 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. Royalty rates for conventional oil under the NRF ranged from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps were set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/$m^3$ compared to the previous royalty curve.

Royalty rates for natural gas under the ARF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF ranged from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps were set at $16.59/GJ. Effective January 1, 2011, the maximum royalty payable under the ARF was reduced to 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the ARF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil and Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of; the gross revenue royalty based on the gross revenue royalty rate of 1-9%, and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF or the ARF.

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

In April 2005, the Government of Alberta implemented the Innovative Energy Technologies Program (the "**IETP**"), which 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 is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-

year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers were only able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that had already elected to adopt such rates as of that date were permitted to switch to Alberta's conventional royalty structure up until February 15, 2011. On January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the ARF. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a $200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010;

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

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

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or freehold production tax, in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

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

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

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* which replaces the existing *Freehold Oil and Gas Production Tax Act* and is intended to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new Act.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.**

The 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 and freehold tax rates 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);

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates 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 and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

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

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

- *Royalty/Tax Regime for High Water-Cut Oil Wells* granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities; and

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in

its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

Land Tenure

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

Each of the provinces of Alberta and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF.

Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its GHG emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

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 which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii)

involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 6 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark (the "**Copenhagen Conference**") resulted in the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. From November 29 to December 10, 2010, a meeting between

representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

In response to the Copenhagen Accord, the Government of Canada indicated on January 29, 2010 that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which were discussed above.

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

On December 23, 2010, the United States Environmental Protection Agency indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by July, 2011 and for refineries by December, 2011.

Alberta

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

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

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

Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which 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.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta 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.

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.

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, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, 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. In accordance with industry practice, the Corporation is not fully insured against all of these risks, nor are all such risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Corporation could incur significant costs. 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.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating 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. Although economic conditions improved towards the latter portion of 2009 and in 2010, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and to result in high volatility in the stock market.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. 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. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any 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 as a result of lower prices, which could result in reduced production of oil or 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 of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and 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.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and 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.

In addition, bank borrowings available to the Corporation may, in part, be determined by the Corporation's borrowing base. A sustained material decline in prices from historical average prices could reduce the Corporation's borrowing base, therefore reducing the bank credit available to the Corporation which could require that a portion, or all, of the Corporation's bank debt be repaid.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, 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 therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

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

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

Because of these factors, the Corporation could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations 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 and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

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

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of

carbon dioxide, methane, nitrous oxide and other so-called "GHGes". There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of GHGes. The Corporation's exploration and production facilities and other operations and activities emit GHGes and require the Corporation to comply with GHG emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. The Corporation may also be required comply with the regulatory scheme for GHG emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for GHG emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of GHGes regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of GHGes and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Climate Change Regulation".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact 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, which could negatively impact the market price of the Common Shares of the Corporation.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Corporation to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves

decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the 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 equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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 herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates 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 and such variations could be material.

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

Actual production and cash flows derived from the Corporation's oil and 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 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 has not been updated and thus does not reflect changes in the Corporation's reserves since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such 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.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the

supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East and other areas of the world have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation will 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.

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.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial

transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

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 impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of Interest

Certain directors of the Corporation are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "*Directors and Officers – Conflicts of Interest*".

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel who are employees of Diaz. 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.

CONFLICTS OF INTEREST

Certain directors and officers of the Corporation may have interests in other oil and gas companies and oil and gas properties which may from time to time conflict with the interests of the Corporation. Any such conflicts will be resolved in accordance with the requirements of the *Business Corporations Act* (Alberta).

HUMAN RESOURCES

At December 31, 2010, Tuscany employed no staff, all of the activities of the Corporation are administered by the staff of related parties and Tuscany pays part of the overhead costs of these related parties.

DIVIDEND POLICY

The Corporation has not paid any dividends on its outstanding shares. 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 it is restricted from paying dividends or redeeming or repurchasing any of its outstanding shares without the written consent of its lender.

DESCRIPTION OF SHARE CAPITAL

Tuscany is authorized to issue an unlimited number of Common Shares. The holders of Common Shares are entitled to receive notice of, to attend and to vote at any meeting of shareholders of the Corporation (other than meetings of a class or series of shares of the Corporation other than the Common Shares as such) and to one vote per share on a ballot. The holders of Common Shares are also entitled to receive dividends as and when declared by the Board of Directors of the Corporation on the Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of dividends. As of the date hereof there were 62,801,825 Common Shares issued and outstanding.

The holders of Common Shares shall be entitled in the event of liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any class of shares of the Corporation ranking equally with the Common Shares in respect of return of capital, in such assets of the Corporation as are available for distribution.

Tuscany is authorized to issue an unlimited number of preferred shares ("**Preferred Shares**"), issuable in series. The board of directors of the Corporation may, by resolution fix before issuance, the designation, rights, privileges, restrictions and conditions to attach to the Preferred Shares of each series, including, without limiting the generality of the foregoing, the rate, form, entitlement and payment of preferential dividends, the redemption price, terms, procedures and conditions of redemption, if any, voting rights and conversion rights, if any. The Preferred Shares shall be entitled to preference over the Common Shares of the Corporation and any other shares of the Corporation ranking junior to the Preferred Shares with respect to the payment of dividends and the distribution of assets in the event of a liquidation, dissolution or winding-up of the Corporation or any other distribution of the assets of the Corporation among its shareholders for the purposes of winding-up its affairs. The Preferred Shares of each series shall rank on a parity with the Preferred Shares of every other series with respect to the priority and payment of dividends and in the distribution of assets in the event of liquidation, dissolution or winding-up of the Corporation. No dividends at any time shall be declared or paid on or set apart for payment on any shares of the Corporation ranking junior to the Preferred Shares unless all dividends, if any, up to and including the dividend payable for the last completed period for which such dividend shall be payable on each series of Preferred Shares then issued and outstanding shall have been declared and paid or set apart for payment at the date of such declaration or payment or setting apart for payment on such shares of the Corporation ranking junior to the Preferred Shares nor shall the Corporation call for the redemption or redeem or purchase for cancellation or reduce or otherwise pay off any of the Preferred Shares or any shares of the Corporation ranking junior to the Preferred Shares unless all dividends up to and including the dividend payable, if any, for the last completed period for which such dividends shall be payable on each series of the Preferred Shares then issued and outstanding shall have been declared and paid or set apart for payment at the date of such call for redemption, purchase, reduction or other payment. The

holders of Preferred Shares shall not, as such, be entitled as a right to subscribe for or purchase or receive any part or any issue of shares or bonds, debentures or other securities of the Corporation. As of the date hereof there were no Preferred Shares issued and outstanding.

MARKET FOR SECURITIES

The Common Shares of the Corporation are listed for trading on the TSX Venture Exchange (the "**TSX-V**") under the symbol "TUS". The following table sets forth the price range and trading volume of such shares on the TSX-V (as reported by the TSX-V) for the periods indicated.

SHARE TRADING

	Common Shares		
Month	High ($)	Low ($)	Volume
2010			
JAN	0.20	0.19	2,772,767
FEB	0.20	0.19	816,100
MAR	0.18	0.18	487,100
APR	0.20	0.18	1,062,410
MAY	0.19	0.18	371,450
JUN	0.18	0.18	332,925
JUL	0.17	0.17	256,750
AUG	0.17	0.17	394,300
SEP	0.17	0.16	491,132
OCT	0.17	0.17	390,280
NOV	0.16	0.16	651,206
DEC	0.18	0.18	1,403,343

DIRECTORS AND OFFICERS

The names, municipalities of residence, positions with Tuscany, principal occupations and the period served as a director, as applicable, of the directors and officers of Tuscany are set out below.

Name and Municipality	Number of Common Shares Beneficially Owned, or Controlled or Directed, Directly or Indirectly	Offices Held and Time as Director	Principal Occupation
Robert W. Lamond[(1)] Calgary, Alberta Canada	25,110,434 [(2)] (39.8%)	Chairman of the Board, director since October 16, 2001	Chairman of the Board President and Chief Executive Officer of Humboldt Capital Corporation ("**Humboldt**"), a TSX-V listed investment company since 1982. Chairman of the Board, President and Chief Executive Officer of Diaz Resources Ltd., ("**Diaz**"), a Toronto Stock Exchange ("**TSX**") listed oil and gas exploration and development company since January, 1998.

Name and Municipality	Number of Common Shares Beneficially Owned, or Controlled or Directed, Directly or Indirectly	Offices Held and Time as Director	Principal Occupation
Donald K. Clark[3] Calgary, Alberta Canada	NIL	Vice President, Operations and Director since October 16, 2001	Chief Operating Officer of Diaz since April 2006. Vice President, Operations of Diaz since January, 1998. Vice-President of Operations of Humboldt since January 1998 Vice-President of Operations of The Corporation since May, 2010
John G.F. McLeod[3] Calgary, Alberta Canada	125,000 (0.2%)	Vice President and Chief Operating Officer. Director since April 10, 2002	Vice President and Chief Operating Officer of the Corporation, President of Paris Energy Inc. an oil and gas exploration and development company listed on the TSX-V and president of California Oil & Gas Corp. a public oil and gas exploration and development company
Charles A. Teare Calgary, Alberta Canada	1,130,000 (2.0%)	Executive Vice President; Director since October 16, 2001	Executive Vice President and Chief Financial Officer of Humboldt since 1982. Executive Vice-President of Diaz since January 1998
Roger W. Hume [1] Kelowna, B.C. Canada	100,000 (0.2%)	Director since May 26, 2009	Independent businessman since 2009
Peter Barker[1] Calgary, Alberta Canada	213,000 (0.3%)	Director since October 7, 2009	CEO of Navitas Inc a private company and Greenearth Travel, a private company
Glen A. Philips Calgary Alberta Canada	9,000 (0.0%)	Director since October 7, 2009	President and CEO of Eiger Energy Ltd., a private oil & gas exploration and production company since 2001.
Jorg M. Reich Neurtingen, Germany	100,240 (0.2%)	Director since October 7, 2009	Independent businessman since 2004.
Brad R. Perry Calgary, Alberta Canada	NIL	Chief Financial Officer	Chief Financial Officer of Diaz and the Corporation
Marshall Kis Calgary, Alberta Canada	NIL	Vice President, Development Geology	Vice President, Development Geology of Diaz, Sharon and the Corporation
C. Steven Cohen Calgary, Alberta Canada	NIL	Corporate Secretary	Partner with Burnet, Duckworth & Palmer LLP (barristers & solicitors)
	26,687,674 (42.5%)		

Notes:

(1) Member of Audit Committee. Additional information with respect to the Audit Committee, including its composition, a copy of its mandate and information with respect to fees paid to the Corporation's auditors is provided under the heading "Audit Committee Information".

(2) 1,292,700 of these Common Shares are held by Mr. Lamond personally. Of the remaining Common Shares 23,367,734 Common Shares are held by Humboldt, 350,000 are held by Lamond Investments Ltd., a related holding company, and 1,000 are held by Mr. Lamond's spouse. Mr. Lamond has ownership of, or control and direction over, 71% of the outstanding shares of Humboldt. Mr. Lamond is also the Chairman of the Board, President and Chief Executive Officer of Humboldt.

(3) Members of the Reserves Committee

The information as to shares beneficially owned or controlled or directed, directly or indirectly, is based upon information furnished to the Corporation by the respective directors or officers.

All of the directors and officers have been engaged for more than five years in their present principal occupations or executive positions with the same or associated companies, except the following: Mr. Perry was the CFO of Corridor Resources Inc. prior to 2006; Mr. McLeod, who was President of Onco Petroleum Inc., a private oil and gas company from 2005 to 2006 and Rally Energy Corporation, an oil and gas exploration and development company from 2001 to 2005; Mr. Hume, who was Vice President, Exploration, Northern Hunter Energy Inc., a private oil and gas company from 2008 to 2009 and Chairman of the Board and Chief Executive Officer, Castle Rock Petroleum Ltd, a public oil and gas company, from 2004 to 2007; and Mr. Barker, who was President and CEO of Goldmark Minerals Ltd from 2006 to 2009, VP and then CEO of Oromonte Resources Inc., a mining company from 2005 to 2006 and President of Travellersmaul.com Ltd from 2001 to 2005.

The term of office of each director expires at the next annual meeting of shareholders.

As at April 18, 2011, the directors and officers of the Corporation as a group, beneficially own, or exercise control or direction over, an aggregate of 26,687,674 Common Shares, representing approximately 42.5% of the issued and outstanding Common Shares.

LEGAL PROCEEDINGS

There are no legal proceedings that the Corporation is or was a party to, or that any of its property is or was subject of, during the last completed financial year, nor are any such legal proceedings known to the Corporation to be contemplated that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of the Corporation other than the following.

On November 4, 2009, MTM Energy Services Inc. has brought an action against Tuscany in the Saskatchewan Court of Queen's Bench for unpaid invoices in the amount of $59,070. Tuscany has denied liability. At this time, only pleadings have been filed, so an assessment of Tuscany's liability is not possible.

During the year ended December 31, 2010 there were: (i) no penalties or sanctions imposed against the Corporation or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Corporation or its subsidiaries that would likely be considered important to a reasonable investor in making an investment decision, and (iii) no settlement agreements the Corporation entered into with a court relating to a 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 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 of the Corporation or any known associate or affiliate of such persons in any transactions 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.

At December 31, 2010, Humboldt Capital Corporation ("Humboldt") and certain of its officers and directors owned 41.6% of the outstanding shares of Tuscany. Humboldt's business includes the ownership, acquisition and sale of securities in other companies and Humboldt owns significant interests in companies in the oil and gas sector, which compete with Tuscany and operate jointly with Tuscany, from time to time, in certain areas. These include Diaz Resources Ltd ("Diaz"), Sharon Energy Ltd. ("Sharon"), and Paris Energy Inc. ("Paris") which also have certain common officers and directors. The following table sets forth the respective ownership of Humboldt and insiders in Tuscany and the companies that may be considered related parties.

	December 31, 2010	December 31, 2009
Tuscany	42.3%	43.7%
Diaz	37.2%	41.4%
Sharon	29.1%	26.8%
Paris	21.3%	20.9%

For the years ended December 31, 2010 and 2009, Tuscany paid the following amounts related to certain overhead services:

Overhead Charged to Tuscany for the year ended December 31,		2010		2009
Diaz Resources Ltd.	$	679,385	$	145,000
Paris Energy Inc.		132,588		130,000

Balance payable to related parties at December 31,		2010		2009
Diaz Resources Ltd.	$	55,682	$	13,657
Paris Energy Inc.		19,342		-

On October 7, 2009 Tuscany and Goldmark completed a merger of the companies by way of a Plan of arrangement approved by the Court of Queens Bench of Alberta. Humboldt and certain of its officers and directors owned 35% of the outstanding shares of Goldmark and were directors and, or officers of Goldmark.

TRANSFER AGENT AND REGISTRAR

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

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 were still in effect

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than McDaniel & Associate Consultants Ltd, the Corporation's independent engineering evaluator and PricewaterhouseCoopers LLP, the Corporation's auditors. None of the “designated professionals” (as defined on National Instrument 51-102) of McDaniel had any registered or beneficial interests, direct or indirect, in any securities or other property of the Corporation or of the Corporation's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it or at any time thereafter and no further interest are to be received by them.

PricewaterhouseCoopers LLP has prepared the auditor's report on the consolidated financial statements of the Corporation for the year ended December 31, 2010. PricewaterhouseCoopers LLP has advised 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.

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

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, 2010 and the related management's discussion and analysis for its most recently completed financial year.

Additional copies of this Annual Information Form, and any financial statements which have been issued by the Corporation, are available upon request by contacting the Corporation at its offices at 1800, 633 - 6th Calgary Alberta, Alberta T2P 2Y5

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate and Terms of Reference of the Audit Committee of the board of director's is attached hereto as Schedule "C".

Composition of the Audit Committee

The members of the Audit Committee are Messrs. Roger W. Hume, Peter Barker and Robert W. Lamond. Mr. Hume is independent (in accordance NI 52-110) and all of the members are financially literate.

Relevant Education and Experience

Roger W. Hume

Mr. Hume is currently an independent businessman Mr. Hume has been the Vice President, Exploration, of Northern Hunter Energy Inc., a private oil and gas company, Chairman of the Board and Chief Executive Officer, Castle Rock Petroleum Ltd, a public oil and gas company listed on the TSX Venture Exchange.

Peter Barker

Mr. Barker is an engineer and an independent businessman was President and CEO of Goldmark Minerals Ltd from 2006 to 2009, VP and then CEO of Oromonte Resources Inc., a mining company from 2005 to 2006 and President of Travellersmaul.com Ltd from 2001 to 2005. Mr. Barker was a senior executive with Canadian Airlines and its predecessor companies for 20 years before that.

Robert W. Lamond

Mr. Lamond is a geologist, educated at the University of Edinburgh, Scotland, and has 40 years of experience in the oil and gas industry. Mr. Lamond has served as Chief Executive Officer and as a member of the Board of Directors and a member of the audit committee of a number of other public companies.

Pre-Approval of Policies and Procedures

The Audit Committee has not pre-approved non-audit services.

External Auditor Services Fees

Audit Fees

The aggregate fees billed by the Corporation's external auditor in each of the last two fiscal years for audit services were $25,000 in 2010 and $54,000 in 2009.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance and related services by the Corporation's external auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements that are included in "Audit Fees" above were $25,000 in 2010 and $42,000 in 2009. These fees related to the review of the Corporation's quarterly and year end financial statements.

Tax Fees

No fees were paid in 2009 or 2010 in relation to services rendered by the Corporation's external auditor for tax compliance, tax advice and tax planning

All Other Fees

In 2009 $12,000 in fees were billed by the Corporation's auditors for the review of the information circular for the corporation in relation to the Plan of arrangement with Goldmark Minerals Ltd.

EXEMPTIONS

The corporation is relying on the exemptions in section 6.1 of the National instrument 52-110

SCHEDULE "A"
FORM 51-101F3
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, 2010, 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 Reserves Committee of the board of directors of the Corporation has:

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

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

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

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

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

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

(f) 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 18, 2011

(Signed) "John G.F. McLeod"
Vice President and Chief Operating Officer

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

(Signed) "D.K. Clark"
Director

(Signed) "Brad Perry"
Chief Financial Officer

McDaniel & Associates Consultants Ltd.

February 9, 2011

Tuscany Energy Ltd.
2000, 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, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010 estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2010, and identifies the respective 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 9, 2011	Canada	-	22,876	-	22,876

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.

"signed by P. A. Welch"

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

Calgary, Alberta
February 9, 2011

SCHEDULE "C"
AUDIT COMMITTEE MANDATE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Tuscany Energy Ltd. ("**Tuscany**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the nature and scope of the annual audit, the oversight of management's reporting on internal accounting standards and practices, the review of financial information, accounting systems and procedures, financial reporting and financial statements and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

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

2. To provide better communication between directors and external auditors;

3. To enhance the external auditor's independence;

4. To increase the credibility and objectivity of financial reports; and

5. To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

6. The Committee will be comprised of at least three (3) directors of Tuscany or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in National Instrument 52-110 — Audit Committees ("**NI 52-110**") unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.

7. The Board of Directors may from time to time designate one of the members of the Committee to be the Chair of the Committee.

8. All of the members of the Committee must be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

9. Oversee the work of the external auditors, including the resolution of any disagreements between management and the external auditors regarding financial reporting.

10. Satisfy itself on behalf of the Board with respect to Tuscany's internal control systems:

    - identifying, monitoring and mitigating business risks; and
    - ensuring compliance with legal, ethical and regulatory requirements.

11. Review the annual and interim financial statements of Tuscany and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:

    - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
    - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
    - reviewing accounting treatment of unusual or non-recurring transactions;
    - ascertaining compliance with covenants under loan agreements;
    - reviewing disclosure requirements for commitments and contingencies;
    - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
    - reviewing unresolved differences between management and the external auditors; and
    - obtain explanations of significant variances with comparative reporting periods.

12. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Tuscany's disclosure of all other financial information and will periodically assess the accuracy of those procedures.

13. With respect to the appointment of external auditors by the Board:

    - recommend to the Board the external auditors to be nominated;
    - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
    - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
    - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

- review and pre-approve any non-audit services to be provided to Tuscany or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre–approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

14. Review with external auditors (and internal auditor if one is appointed by Tuscany) their assessment of the internal controls of Tuscany, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Tuscany and its subsidiaries.

15. Review risk management policies and procedures of Tuscany (i.e. hedging, litigation and insurance).

16. Establish a procedure for:

- the receipt, retention and treatment of complaints received by Tuscany regarding accounting, internal accounting controls or auditing matters; and

- the confidential, anonymous submission by employees of Tuscany of concerns regarding questionable accounting or auditing matters.

17. Review and approve Tuscany's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of Tuscany.

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

The Committee may also retain persons having special expertise and/or obtain independent professional advise to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Tuscany without any further approval of the Board.

Meetings and Administrative Matters

18. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.

19. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

20. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.

21. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

22. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

23. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

24. The Committee may invite such officers, directors and employees of the Corporation as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

25. Minutes of the Committee will be recorded and maintained and circulated to directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

26. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

27. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee, each member will hold such office until the Committee is reconstituted.

28. Any issues arising from these meetings that bear on the relationship between the Board and management should be communicated to the Chairman of the Board by the Committee Chair.