



ANNUAL INFORMATION FORM
For the Year Ended December 31, 2010

April 29, 2011

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FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements and forward-looking information within the meaning of applicable securities legislation. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "should", "believe", "intend", "forecast", "plans", "guidance" and similar expressions is intended to identify forward-looking statements or information.

More particularly and without limitation, this Annual Information Form and the documents incorporated by reference herein contain forward-looking statements and information relating to the following:

- the performance characteristics of the Corporation's oil, NGLs and natural gas properties;
- oil, NGLs and natural gas production levels;
- the size of the oil, NGLs and natural gas reserves;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development;
- future funds from operations;
- capital programs;
- debt levels;
- future royalty rates;
- future depletion, depreciation and accretion rates;
- treatment under governmental regulatory regimes and tax laws; and
- capital expenditure programs.

The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are based on certain key expectations and assumptions made by the Corporation, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities and the availability and cost of labour and services.

Although the Corporation believes that the expectations reflected in the forward-looking statements and information in this Annual Information Form and in the documents incorporated by reference herein are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, risks associated with the oil and gas industry in general, such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources, changes in tax, royalty and environmental legislation and the risks under the heading "Risk Factors" in this Annual Information Form. Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Readers are cautioned that the foregoing list of factors and risks is not exhaustive.

The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are made as of April 29, 2011 and, unless so required by applicable law, the Corporation undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise. The forward-looking statements and information contained in this Annual Information Form and in the documents incorporated by reference herein are expressly qualified by this cautionary statement.

PART 1: ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl or bbl	Barrel	Mcf or mcf	thousand cubic feet
Bbls or bbls	Barrels	Mmcf	million cubic feet
Mbbls	thousand barrels	Mcf/d or mcf/d	thousand cubic feet per day
Mmbbls	million barrels	Mmcf/d	million cubic feet per day
Mstb	thousand stock tank barrels	Mbtu/d	thousand British Thermal Units per day
Bbls/d or bbls/d	barrels per day	MMBTU or Mmbtu	million British Thermal Units
BOPD or bopd	barrels of oil per day	Bcf or bcf	billion cubic feet
NGLs	natural gas liquids	GJ	Gigajoule

AECO EnCana Corp's natural gas storage facility located at Suffield, Alberta

API American Petroleum Institute

API^o An indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28^o API or higher is generally referred to as light crude oil.

ARTC Alberta Royalty Tax Credit

BOE barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

BOE/d barrel of oil equivalent per day

m³ cubic meters

MBOE 1,000 barrels of oil equivalent

\$000 or M\$ thousands of dollars

WTI West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.

In this Annual Information Form, references to "dollars" and "\$" are to the currency of Canada, unless otherwise indicated.

PART 2: INCORPORATION AND ORGANIZATION

Vecta Energy Corporation ("**Vecta**" or the "**Corporation**") was incorporated under the *Business Corporations Act* (Alberta) (the "**ABCA**") on December 20, 1995 as "Kroes Energy Inc.". On May 1, 1997, the Corporation amalgamated with Hogar Energy Inc., its wholly-owned subsidiary. The common shares of the Corporation (the "**Common Shares**") commenced listing and trading on the TSX Venture Exchange (the "**TSXV**") on October 9, 1996.

In July 2008, the Corporation acquired (the "**Vecta Acquisition**") approximately 97% of the issued and outstanding common shares (the "**Vecta Shares**") and the debenture (the "**Vecta Debenture**") of a private company having the name "Vecta Energy Corporation" ("**Old Vecta**"), by way of a take-over bid pursuant to applicable securities laws, by issuing 29,936,439 Common Shares, 5,147,898 Class 1 performance warrants (the "**Class 1 Performance Warrants**") and 5,312,500 Class 2 performance warrants (the "**Kroes Class 2 Performance Warrants**"). The remaining Old Vecta Shares were acquired by the Corporation under the compulsory acquisition provisions of the ABCA. On October 1, 2008, the Corporation and its wholly-owned subsidiary Old Vecta amalgamated under the name of "Kroes Energy Inc.".

On June 3, 2009, a special resolution of its shareholders was passed to change the name of the issuer resulting from the amalgamation of the Corporation and Old Vecta to "Vecta Energy Corporation". The Common Shares continued trading on the TSXV under a new trading symbol "VER" effective June 23, 2009.

The Corporation's head office is located at Suite 1840, 444 – 5th Avenue S.W., Calgary, Alberta T2P 2T8. The Corporation's registered office is located at Suite 1200, 700 – 2nd Street S.W., Calgary, Alberta T2P 4V5.

PART 3: BUSINESS OF THE CORPORATION

3.1 General

Vecta is a growth-oriented, exploration focused oil and natural gas company. The Corporation is involved in the production, exploration and development of resource properties in the Brewster and Harmattan areas of Alberta. As at December 31, 2010, Vecta's oil and gas assets produced approximately 47 boe/d of oil, natural gas and NGLs, weighted 90% to natural gas and 10% to NGLs. Effective June 1, 2010, Vecta sold its shallow gas assets in central Alberta for \$650,000. Vecta currently owns approximately 12,000 gross (2,100 net) acres of undeveloped land. See "Statement of Reserves Data and Other Oil and Gas Information" in this Annual Information Form.

3.2 Relevant Three Year History

On January 17, 2008, the Corporation sold its 25% interest in the Icos Block, Cedros Peninsula, Trinidad for US\$250,000. In addition, the Corporation retained a 1% overriding royalty on any production from the block that may be developed below 4,000 feet, subject to a maximum of US\$1.0 million.

On February 8, 2008, the Corporation announced that it entered into an agreement with Old Vecta, whereby the Corporation and Old Vecta would combine, as equals, all of their businesses and operations. The business combination was to be accomplished by the Corporation making a take-over bid for all of the issued and outstanding Vecta Shares and the Vecta Debenture. The transaction was considered a "fundamental acquisition" pursuant to TSXV Policy 5.3 *Acquisitions and Dispositions of Non-Cash Assets*. Under the Vecta Acquisition, each holder of a Vecta Share was offered 2.456633 Common Shares and 0.54220918 of one Class 1 Performance Warrant. In exchange for cancellation of the Vecta Debenture, which was a secured debenture in the principal amount of \$850,000 granted by Old Vecta to Vecta Resources, LLC, the holder thereof was offered 6,612,500 Common Shares and 5,312,500 Class 2 Performance Warrants. The Class 1 Performance Warrants and the Class 2 Performance Warrants would convert into 5,312,500 Common Shares

40 days following closing of the transaction, with the allocation of those additional Common Shares to be determined by the Corporation's share price performance over such 40-day period. If the take-over bid was successful, the Corporation would issue 36,000,000 Common Shares to the former shareholders of Old Vecta and to the former holder of the Vecta Debenture.

On May 2, 2008, the Corporation announced that a definitive formal agreement dated April 28, 2008 was signed with Old Vecta, outlining all of the terms related to the business combination of the Corporation and Old Vecta.

On July 30, 2008, the board of directors and the management team of the Corporation were restructured. The board accepted resignations from three directors, namely, David Powell, James Werbicki and Edward Southern. Fred Callaway also tendered his resignation as President and Chief Executive Officer of the Corporation and Edward Southern resigned from his position as Executive Vice President. Thomas Coffman, Allen Gilmer, Charles Selby and Kenneth West were appointed to the board of directors of the Corporation. Fred Callaway, C. James Cummings, Stewart Gossen and Darrell Zakreski continued to serve as directors. The new management team consisted of Fred Callaway (Executive Chairman), Thomas Coffman (President and Chief Executive Officer), Stewart Gossen (Vice President, Finance and Chief Financial Officer) and Charles Selby (Vice President, Business Development).

On July 30, 2008, the Corporation announced that it had taken up and paid for all Vecta Shares as well as the Vecta Debenture tendered to the take-over bid. The Corporation issued 29,936,439 Common Shares, 5,147,881 Class 1 Performance Warrants and 5,312,500 Class 2 Performance Warrants in payment for approximately 97% of Old Vecta's issued and outstanding shares and the Vecta Debenture. The remaining Vecta Shares were acquired under the compulsory acquisition provisions of the ABCA.

On August 5, 2008, the Corporation issued 2.8 million incentive stock options to its employees, officers and directors. The options are exercisable at a price of \$0.065 per share and will expire on July 31, 2013.

On August 8, 2008, the Corporation advised that it increased the exercise price of 2.8 million stock options dated July 31, 2008 and 1.66 million stock options issued dated August 22, 2007 to \$0.10 in order to comply with the minimum requirement under TSXV policies.

On October 1, 2008, the Corporation acquired all of the remaining Vecta Shares under the compulsory acquisition provisions of the ABCA and amalgamated with Old Vecta. As a result of the Vecta Acquisition, the Corporation issued in aggregate 29,936,439 Common Shares, 5,312,500 Class 2 Performance Warrants and 737,584 common shares for the remaining 3% compulsory acquisition. The Class 2 Performance Warrants subsequently converted into 5,312,500 Common Shares.

In November 2008, the Corporation arranged a \$1.0 million bank line of credit with the National Bank of Canada to fund its western Canada gas development program and other corporate purposes. The terms of the loan repayment provided for interest only, but were subject to availability, review and the lender's right of demand.

On June 22, 2009, the Corporation changed its name to "Vecta Energy Corporation".

On July 17, 2009, the Corporation announced that C. James Cummings resigned his position as a director of the Corporation.

On August 31, 2009, the Corporation announced that Stewart Gossen resigned his position as Vice President, Finance, Chief Financial Officer and Corporate Secretary of the Corporation.

Due to low natural gas prices, the National Bank of Canada reduced the \$1.0 million credit facility to \$500,000 and the Corporation became non-compliant with its loan agreement. To remedy this, on October 19, 2009, the Corporation entered into nine secured loan agreements (collectively, the "**Secured Loans**") with directors of the Corporation as well as other related parties for an aggregate principal amount of \$500,000. The

proceeds of the Secured Loans were used to retire the Corporation's bank loan and for other corporate purposes. The Secured Loans were scheduled to mature on October 1, 2010 (see "Recent Developments") and had an interest rate of 15% per annum. The Secured Loans are secured by all the Corporation's interests in petroleum and natural gas rights and other assets of the Corporation.

On November 10, 2009, the Corporation entered into an agreement to farm out a 25% interest in Brewster well 8-22-43-13W5 that was drilled and suspended in July 2008. The well was perforated and fractured but when tested, failed to produce hydrocarbons. The farmee agreed to pay for 100% of completion and connection costs to earn its interest. In addition to the farm-out, the same farmee had the option to drill, test, complete and tie-in a well at its cost on each of adjacent sections 26 and 27. The Corporation holds a 7.5% working interest in these two sections and retains a 3% interest after the wells are completed and on stream. In addition, the Corporation sold its 25% interest in 5 sections of land in its central Alberta shallow gas play for gross proceeds of \$48,000 and payment was received in October 2009. Effective June 1, 2010, the Corporation sold its interests in the Warwick shallow gas area of central Alberta. The Corporation's share of production from the area was approximately 360 mcf per day and it received proceeds of \$650,000 from the sale. Over the past 18 months immediately preceding the sale, the continuing depression in the price of natural gas and significant volume decline experienced from the Warwick wells resulted in a substantial revenue reduction for the Corporation. Accordingly, the Corporation elected to sell those assets in order to fund existing operations and to pursue merger and/or acquisition opportunities. The sale was approved by the TSXV and was completed on August 4, 2010. The Corporation retains all of its various working interests in approximately 16,000 acres of lands in the foothills of Alberta and north eastern British Columbia, and in the approximately 20 barrels per day of oil equivalent production from the Brewster area.

On October 1, 2010, holders of the Secured Loans agreed to extend the maturity date to November 1, 2010 if the Corporation entered into a joint venture agreement covering oil and gas operations in Montana. The directors of the Corporation further agreed that, upon execution of a letter of intent with respect to a joint venture, the maturity date would be further extended to February 1, 2011 to allow for completion of documents and financing.

On November 2, 2010, the Corporation issued 1,400,000 Common Shares at a price of \$0.05 per share to Rembrandt Resources Ltd. in satisfaction of accounting fees owing to its principal, who is Vecta's Controller. The liability accumulated over a 14-month period as a result of the Corporation's 2009 cash conserving actions that significantly reduced cash compensation.

In October 2010, the Corporation reached an agreement to farm out a portion of its 50% interest in Section 36-31-3 W5M in the Harmattan area. The farmee will drill and complete a well to earn 70% and the Corporation will retain 15% carried working interest (one half of the 30% owned jointly with Perpetual Energy). The well was spudded on November 29, 2010 and is planned to test the Cardium formation with a horizontal well and multi stage frac treatment.

On November 2, 2010, the Corporation signed a letter of intent with a private company (the "**Joint Venture Partner**") to enter into a 50/50 joint venture to participate in the Exshaw/Bakken light oil resource play in north central Montana. The Joint Venture Partner will continue to assemble additional land holdings for the joint venture which are deemed prospective for the Exshaw/Bakken formation. The Corporation will manage the joint venture from its Calgary office and the technical team of the Joint Venture Partner will be responsible for the operations, including all engineering, land, geological and geophysical functions in the evaluation and development of the project.

3.3 Recent Developments

On January 20, 2011, the board of directors of the Corporation appointed Diane M. Zuber, CFA as the Vice President, Finance and Chief Financial Officer of the Corporation.

On January 20, 2011, the holders of the Secured Loans agreed to extend the maturity date to April 1, 2011 to allow for completion of the necessary documentation and financing of the joint venture.

On March 8, 2011, the Corporation signed a Joint Venture Agreement (the "JV Agreement") with Vecta Oil & Gas, Ltd. ("VOG"), of Dallas, Texas to participate in an Exshaw/Bakken light oil resource play in north central Montana.

The objective of the JV Agreement is to combine technical and financial expertise to pursue the prospective Exshaw/Bakken oil resource play and additional high potential objectives in the Sweetgrass Arch area of north central Montana. Under the terms of the JV Agreement, Vecta will make a capital contribution of US\$27.0 million to initially evaluate the play, including the drilling of 2-4 vertical wells and 3-4 horizontal wells (the "Evaluation Phase"), and VOG will assign more than 112,000 net acres (approximately 175 sections) of leasehold and other development rights to the joint venture (the "JV") within Pondera, Glacier and Toole Counties of Montana (the "Project Area"). Additional leasehold is also being acquired by VOG that is expected to augment the land position assignable to the JV at closing. It is contemplated in the JV Agreement that Vecta and VOG will both hold a 50% interest in the JV.

The Evaluation Phase includes payment of a leasehold equalization fee to VOG; multiple seismic programs within the Project Area, including the acquisition of proprietary multicomponent (9C) seismic; the drilling of two to four vertical test wells, and the drilling of a minimum of two or more horizontal test wells. The Evaluation Phase is scheduled to commence shortly after closing.

Vecta will manage all financial and administrative functions for the JV from its Calgary office and VOG will be responsible for operations, including all engineering, land, geological and geophysical functions in the evaluation and development of the Project Area. An Operating Committee consisting of members appointed by Vecta and VOG will govern the JV. On March 8, 2011, Vecta also announced that it entered into an engagement letter with Wellington West Capital Markets Inc. ("Wellington"), pursuant to which Vecta will issue subscription receipts, by way of a short form prospectus offering (the "Offering"), with Wellington acting as the sole agent on a "commercially reasonable best efforts" basis, for gross proceeds of at least \$32 million to participate in and to meet work commitments associated with the JV and for general corporate purposes. On March 8, 2011, Vecta filed a preliminary prospectus with the securities regulatory authorities in all of the provinces of Canada (except Quebec) in connection with the Offering. The filed preliminary prospectus is available for review at www.sedar.com under Vecta's profile. When the Corporation has met certain release conditions, the proceeds of the Offering will be released to the Corporation and each Subscription Receipt will be automatically converted into one common share of the Corporation. The issue price of the subscription receipts will be determined in the context of the market and the Offering is subject to certain conditions including, but not limited to, the execution of a definitive agency agreement with Wellington and the receipt of regulatory and exchange approvals. On March 24, 2011, the holders of the Secured Loans agreed to extend the maturity date to April 29, 2011 to allow for completion of the due diligence, regulatory and financial requirements.

On April 8, 2011, the Corporation announced an extension of the closing date of the Joint Venture agreement to April 29, 2011 to allow adequate time for completion of due diligence, regulatory and financial requirements.

3.4 Strategy

Vecta's business plan is to focus on growth in both cash flow from operations and net asset value. To accomplish this, the Corporation will focus on enhancing its asset base through joint venture opportunities, land acquisitions, corporate acquisitions, property acquisitions, exploratory drilling and development drilling.

The Corporation expects to internally generate exploration and development opportunities possessing medium risk and multiple prospective productive zone potential with a prudent exposure to higher

risk/reward prospects. The Corporation intends to maintain a balance between exploration, development and exploitation drilling, combined with acquisition opportunities that meet the Corporation's business parameters. To achieve sustainable and profitable growth, the Corporation will control the timing and costs of its projects wherever possible. Accordingly, the Corporation will seek to become the operator of its properties to the greatest extent possible. Further, to minimize competition within its geographic areas of interest, the Corporation will, after giving consideration to its risk profile, strive to maximize its working interest ownership in its properties. While the Corporation intends to have the skills and resources necessary to achieve its objectives, participation in exploration and development in the oil and natural gas industry has a number of inherent risks. See "Risk Factors".

In reviewing potential drilling or acquisition opportunities, the Corporation gives consideration to the following criteria:

- (1) risk capital required to secure or evaluate the investment opportunity;
- (2) the potential return on the project, if successful;
- (3) the likelihood of success; and
- (4) the risked return versus cost of capital.

In general, the Corporation will use a portfolio approach in developing a large number of opportunities with a balance of risk profiles and commodity exposure, in an attempt to generate sustainable high levels of profitable production and financial growth.

The board of directors of the Corporation may, in its discretion, approve acquisitions that do not conform to these guidelines based upon its consideration of the qualitative aspects of the subject properties including risk profile, technical upside, reserve life and asset quality.

3.5 Price Risk Management

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside management's control. These factors include, but are not limited to, the following:

- (1) world market forces, including the ability of OPEC to set and maintain production levels and prices for crude oil;
- (2) political conditions, including the risk of hostilities in the Middle East and other regions throughout the world;
- (3) increases or decreases in crude oil quality and market differentials;
- (4) the impact of changes in the exchange rate between Canada and U.S. dollars on prices received by the Corporation for its crude oil and natural gas;
- (5) North American market forces, most notably shifts in the balance between supply and demand for crude oil and natural gas and the implications for the price of crude oil and natural gas;
- (6) global and domestic economic and weather conditions;
- (7) price and availability of alternative fuels; and
- (8) the effect of energy conservation measures and government regulations.

Currently, the Corporation does not have any price risk management transactions in place.

3.6 Revenue Sources

For the year ended December 31, 2010, 79% of the revenue from Vecta's properties before royalties was derived from natural gas and 21% was derived from oil and NGLs. Production is sold to marketers at delivery points in or close to the producing field.

3.7 Competition

There is strong competition relating to all aspects of the oil and natural gas industry. The Corporation will actively compete for capital, skilled personnel, undeveloped land, reserves acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which may have greater technical and financial resources than the Corporation. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world-wide basis and as such have greater and more diverse resources on which to draw.

3.8 Personnel

As at December 31, 2010, Vecta had four contract employees. As at April 29, 2011, Vecta had five contract employees.

PART 4: STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

In accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities, Sproule Associates Limited ("Sproule") prepared an independent engineering evaluation, as at December 31, 2010 of Vecta's oil and gas interests and reserves. The date of preparation of the "Sproule Report" was March 21, 2010. The tables below are a summary of the oil, NGL and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the Sproule Report based on forecast price and cost assumptions. The tables summarized the data contained in the Sproule Report and as a result may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly. **The net present value of future net revenue attributable to the Corporation's reserves is stated without provision for interest costs and general and administrative costs, but after providing for estimated royalties, production costs, development costs, other income, future capital expenditures, and well abandonment costs for only those wells assigned reserves by Sproule. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Corporation's reserves estimated by Sproule represent the fair market value of those reserves. Other assumptions and qualifications relating to costs, prices for future production and other matters are summarized herein. The recovery and reserve estimates of the Corporation's oil, NGL and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.**

The Sproule Report is based on certain factual data supplied by the Corporation and Sproule's opinion of reasonable practice in the industry. The extent and character of ownership and all factual data pertaining to the Corporation's petroleum properties and contracts (except for certain information residing in the public domain) were supplied by Vecta to Sproule and accepted without any further investigation. Sproule accepted this data as presented and neither title searches nor field inspections were conducted.

Table 1 Summary of Oil and Gas Reserves

NI 51-101
As of December 31, 2010
Forecast Prices and Costs

Reserves								
	Light and Medium Oil		Heavy Oil		Natural Gas (non-associated and associated)		Natural Gas Liquids	
Reserve Category	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)	Gross (Mbbbl)	Net (Mbbbl)
Proved								
Developed Producing	0.0	0.0	0.0	0.0	121	151	4.3	13.2
Developed Non-Producing	0.0	0.0	0.0	0.0	0	0	0.0	0.0
Undeveloped	0.0	0.0	0.0	0.0	0	0	0.0	0.0
Total Proved	0.0	0.0	0.0	0.0	121	151	4.3	13.2
Probable	0.0	0.0	0.0	0.0	42	46	1.5	2.6
Total Proved plus Probable	0.0	0.0	0.0	0.0	164	197	5.9	15.8

Table 2 Summary of Net Present Values of Future Net Revenue

NI 51-101
As of December 31, 2010
Forecast Prices and Costs

Net Present Values of Future Net Revenue						
Reserve Category	0 (M\$)	5 (M\$)	10 (M\$)	15 (M\$)	20 (M\$)	Before Tax Net Value 10%/Year (\$/boe)
Proved						
Developed Producing	1,282	1,034	872	760	678	22.71
Developed Non-Producing	0	0	0	0	0	0.00
Undeveloped	0	0	0	0	0	0.00
Total Proved	1,282	1,034	872	760	678	22.71
Probable	326	166	94	58	38	9.15
Total Proved plus Probable	1,608	1,200	966	818	716	19.84

Note: NPV of Future Net Revenue include all resource income:
 Sale of oil, gas, by-product reserves, Processing third party reserves and other income.

Unit Values are based on net reserve volumes.

Table 3 Total Future Net Revenue, Undiscounted

**NI 51-101
As of December 31, 2010
Forecast Prices and Costs**

Reserve Category	Revenue (M\$)	Royalties (M\$)	Operating Costs (M\$)	Development Costs (M\$)	Well Abandonment /Other Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)
Proved	1,973	167	518	0	6	1,282
Proved plus Probable	2,621	228	779	0	6	1,608

Table 4 Net Present Value of Future Net Revenue

**NI 51-101
As of December 31, 2010
Forecast Prices and Costs**

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M\$)	Unit Value Before Income Taxes (Discounted at 10%/Year) (\$/boe)
Proved	Light and Medium Crude Oil (including solution gas and associated by-products)	0	0
	Heavy Oil (including solution gas and associated by-products)	0	0
	Natural Gas (including associated by-products)*	872	22.71
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated by-products)	0	0
	Heavy Oil (including solution gas and associated by-products)	0	0
	Natural Gas (including associated by-products)*	966	19.85

*Includes corporate Capital CGA, if applicable

Unit Values are based on net reserve volumes

Table 5 Summary of Pricing and Inflation Rate Assumptions

NI 51-101
As of December 31, 2010
Forecast Prices and Costs

Year	WTI Cushing Oklahoma (\$US/bbl)	Edmonton Par Price 40° API (\$Cdn/bbl)	Cromer Medium 29.3° API (\$Cdn/bbl)	Natural Gas ¹ AECO Gas Prices (\$Cdn/MMBtu)	Pentanes Plus FOB Field Gate (\$Cdn/Bbl)	Butanes FOB Field Gate (\$Cdn/bbl)	Inflation Rate ² (%/Year)	Exchange Rate ³ (\$US/\$Cdn)
HISTORICAL								
2007	72.27	77.06	65.36	6.65	77.33	63.71	2.0	0.935
2008	99.59	102.85	93.05	8.15	104.70	75.09	1.0	0.943
2009	61.63	66.20	62.77	4.19	68.13	47.07	2.0	0.880
2010	79.43	77.81	73.66	4.16	84.21	57.04	1.0	0.971
FORECAST								
2011	88.40	93.08	85.63	4.04	95.32	62.44	1.5	0.932
2012	89.14	93.85	86.34	4.66	96.11	62.95	1.5	0.932
2013	88.77	93.43	85.02	4.99	95.68	62.67	1.5	0.932
2014	88.88	93.54	84.18	6.58	95.79	62.75	1.5	0.932
2015	90.22	94.95	85.45	6.69	97.24	63.69	1.5	0.932
2016	91.57	96.38	86.74	6.80	98.71	64.65	1.5	0.932
2017	92.94	97.84	88.05	6.91	100.20	65.63	1.5	0.932
2018	94.34	99.32	89.38	7.02	101.71	66.62	1.5	0.932
2019	95.75	100.81	90.73	7.14	103.25	67.63	1.5	0.932
2020	97.19	102.34	92.10	7.26	104.81	68.65	1.5	0.932

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

⁽²⁾ Inflation Rates for forecasting prices and costs.

⁽³⁾ Exchange rates used to generate the benchmark reference prices in this table.

Note:

Product sale prices will reflect these reference prices with further adjustments for quality and transportation to point of sale.

Table 6 Reconciliation of Company Gross ⁽¹⁾ Reserves (Before Royalty) by Principal Production Type

NI 51-101
As of December 31, 2010
Forecast Prices and Costs

Factors	Light and Medium Oil			Heavy Oil			Coalbed Methane		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved plus Probable (Mbbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved plus Probable (MMcf)
December 31, 2009	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
Extensions	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
Technical Revisions	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
Production	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
December 31, 2010	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0
Factors	Associated and Non-Associated Gas			Natural Gas Solution			Natural Gas Liquids		
	Gross Proved ((MMcf)	Gross Probable (MMcf)	Gross Proved plus Probable (MMcf)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved plus Probable (MMcf)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved plus Probable (Mbbbl)
December 31, 2009	446.6	166.3	612.9	0	0	0	3.1	1.7	4.8
Extensions	0	0	0	0	0	0	0.0	0.0	0.0
Improved Recovery	0	0	0	0	0	0	0.0	0.0	0.0
Technical Revisions	32	-18	15	0	0	0	2.1	-0.2	1.9
Discoveries	0	0	0	0	0	0	0.0	0.0	0.0
Acquisitions	0	0	0	0	0	0	0.0	0.0	0.0
Dispositions	269.7	105.8	375.5	0	0	0	0.0	0.0	0.0
Economic Factors	0	0	0	0	0	0	0.0	0.0	0.0
Production	87.9	0	87.9	0	0	0	0.8	0	0.8
December 31, 2010	121	42.5	164.5	0	0	0	4.4	1.5	5.9

(1) Gross Reserves means the Corporation's working interest reserves before calculation of royalties and before consideration of the Corporation's royalty interests.

PART 5: ADDITIONAL INFORMATION RELATING TO RESERVES DATA

5.1 Undeveloped Reserves

The Corporation has no proved undeveloped reserves. Probable undeveloped reserves are generally those reserves indicated by analogy to be productive and lands contiguous to production. All assigned probable undeveloped reserves are planned to be on stream within a two (2) year time frame.

5.2 Significant Factors or Uncertainties

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. Vecta's reserves are evaluated by Sproule Associated Limited, an independent engineering firm.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative.

5.3 Future Development Costs

The Corporation does not expect to incur any capital development costs related to its proved and probable reserves.

PART 6: OTHER OIL AND GAS INFORMATION

6.1 Oil and Gas Properties and Wells

The Corporation's important properties, plants, facilities and installations are:

- (1) located exclusively in Canada and more specifically within the Provinces of Alberta and British Columbia.
- (2) located onshore.
- (3) none that are not producing with reserves attributed.
- (4) without associated statutory or mandatory relinquishments, surrenders, back-ins, or changes in ownership.

The number of the Corporation's working interest oil wells and gas wells producing and non-producing, expressed on a gross and net basis, by location, is as follows:

	Oil Wells				Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	-	-	-	-	2.0	0.18	8.0	2.1
British Columbia	1.0	0.0	-	-	-	-	-	-

The Corporation has a 2.5% royalty interest in a producing gas/liquids well.

6.2 Properties With No Attributed Reserves

The Corporation has an interest in unproved properties with a gross area of 12,800 acres or 5,120 hectares.

The Corporation y has an interest in unproved properties with a net area of 2,415 acres or 966 hectares.

All of the Corporation's unproved properties are located in Canada.

The Corporation has no work commitments associated with its unproved properties.

The Corporation does not expect its rights to explore, develop and exploit its unproved property to expire before December 31, 2011.

6.3 Forward Contracts

The Corporation is not bound by any agreements under which it may be precluded from fully realizing, or may be protected from the full effect of, future market prices for oil or gas (describe the agreement(s), discussing dates or time periods and summaries or ranges of volumes and contracted or reasonably estimated values.)

6.4 Additional Information Concerning Abandonment and Reclamation Costs

- a) The estimate of costs is determined through a review of engineering studies, industry guidelines, and management's estimate on a site by site basis.
- b) The number of net wells for which the Company expects to show such costs is 2.3.
- c) An estimate of abandonment costs:

NI 51-101
TOTAL PROVED PLUS PROBABLE RESERVES
PRODUCTION AND CASH FLOW FORECASTS
ABANDONMENTS SCHEDULE
FORECAST PRICES & COSTS - SPROULE DECEMBER 31, 2010 PRICES
EFFECTIVE DATE: DECEMBER 31, 2010

	ABANDONMENT COSTS	
	UNDISCOUNTED	DISCOUNTED @ 10%
	<i>M\$</i>	<i>M\$</i>
2010	0	0
2011	0	0
2012	0	0
2013	0	0
2014	0	0
2015	0	0
2016	0	0
2017	0	0
2018	0	0
Sub.	0	0
Rem.	6	1
Total	6	1

- d) The entire amount disclosed in (c) herein was deducted as abandonment costs in estimating the Corporation's future net revenue.
- e) None of the amounts disclosed in (c) herein are expected to be paid in the next three (3) financial years.

6.5 Tax Horizon

The Corporation is not required to pay income taxes for 2010 and is not expected to pay income taxes for the duration of its reserves life.

6.6 Costs Incurred

Costs incurred for year ended December 31, 2010

Property acquisition – undeveloped land	\$ 58
Exploration Costs	20,700
Development Costs	(3110)
Total	\$ 17,648

6.7 Exploration and Development Activities

In the Corporation's most recent financial year ended December 31, 2010, it did not complete any exploration or development wells. The Corporation holds a 2.5% royalty interest in a well that was completed in 2010 at no cost to the Corporation.

The Corporation's most important exploration and development activities are all located in Canada. The company does not intend to participate directly in exploration activities in 2011. It may participate in such activity by farming out portions of its interests in exploratory lands.

6.8 Production Estimates

Estimated First Year Production – Brewster/Harmattan¹⁾

	Gross Production ⁽¹⁾			Net Production		
	Light and Medium Crude Oil (MSTB)	Natural Gas Liquids (MSTB)	Natural Gas (MMSCF)	Light and Medium Crude Oil(MSTB)	Natural Gas Liquids (MSTB)	Natural Gas (MMSCF)
Proved						
Developed Producing	0	1.0	28	0	3.5	35
Developed Non-Producing	0	0	0	0	0	0
Undeveloped	0	0	0	0	0	0
Total Proved	0	1.0	28	0	3.4	35
Total Probable	0	0	0	0	0	0
Total Proved Plus Probable	0	1.0	28	0	3.5	35

(1) Excludes royalty production

6.9 Selected Consolidated Financial Information

Daily average production, unit prices, netbacks and costs are disclosed in the financial statements of the Corporation.

6.10 Production Totals by Field for 2010

	Gross Production			Net Production		
	Light and Medium Crude Oil (MSTB)	Natural Gas Liquids (MSTB)	Natural Gas (MMSCF)	Light and Medium Crude Oil(MSTB)	Natural Gas Liquids (MSTB)	Natural Gas (MMSCF)
Canada						
Brewster, Alberta	-	0.8	28.4	-	0.6	22.7
Harmattan ⁽¹⁾	-	0.8	4.4	-	0.8	4.4
Plain/Warwick	-	-	59.5	-	-	52.4
Total	-	1.6	92.3	-	1.4	79.5

(1) Overriding royalty volumes

PART 7: DIRECTORS AND OFFICERS OF THE CORPORATION

The name, province and country of residence and principal occupation for the last five years of each of the directors and executive officers of the Corporation are as follows:

Name and Municipality of Residence	Office	Principal Occupation	Director /Officer Since	Common Shares Held as at the Date Hereof
Thomas D. Coffman ³ Texas, U.S.A.	President, Chief Executive Officer and Director	President and Chief Executive Officer of the Corporation; President of Thomas D. Coffman, Inc. , a private oil and gas company based in Austin, Texas, since 1977. ; Co-founder and Limited Partner of Vecta Oil & Gas Ltd., 2000 – present, Chairman and Chief Executive Officer of Old Vecta from October 2005 to July 2008	July 2008	215,002 (0.29%)
Fred Callaway Alberta, Canada	Executive Chairman	Retired oil and gas executive. Prior thereto, President of Kroes Energy 1996 – 2008.	June 1996	2,392,639 (3.3%)
Stewart Gossen ^{1,3,4} Alberta, Canada	Director	Executive Vice President of Source Rock Energy Inc. an oil and gas company, Vice President, Finance and Chief Financial Officer of the Corporation until August 2009 and prior thereto, Vice President of Enbridge Inc., a publicly traded energy company.	June 2006	255,000 (0.35%)
Charles V. Selby ³ Alberta, Canada	Vice President, Business Development and Director	Lawyer, Selby Professional Corporation; corporate financial advisor; President of Caledonian Royalty Corporation a private oil and gas company focusing on the strategic acquisition of oil and gas royalties, Vice President and Corporate Secretary of Pengrowth Corporation, administrator of Pengrowth Energy Trust (now Pengrowth Energy Corporation), an energy royalty trust from 1993 to 2009; Chairman, President, Chief Financial Officer and a director of AltaCanada Energy Corp., a public oil and gas company	July 2008	Nil

Darrell Zakreski ^{1,2} Alberta, Canada	Director	Commercial Real Estate Developer	January 2002	2,997,856 (4.1%)
Kenneth West ^{1,2} Alberta, Canada	Director	Retired oil and gas executive since 2005 and prior thereto, Vice President, Exploration of Crestar Energy Inc., a publicly traded oil and gas exploration and development company	July 2008	61,416 (0.08%)
Allen Gilmer ³ Texas, USA	Director	Geophysicist; co-founder, Chairman and Chief Executive Officer of Drilling Info Inc., a privately held oil and gas upstream infomediary and oil and gas trade and investment enabler based in Austin, Texas	July 2008	41,320 (.06%)
Diane Zuber ⁷ Alberta, Canada	Vice President Finance and Chief Financial Officer	Vice President Finance of the Corporation. Prior thereto, financial consultant to Vecta; VP Corporate Planning, Barron Energy Corporation; Senior Financial Analyst at Kinnear Financial Limited, Senior Analyst, Business Development at Pengrowth Management Limited.	January 2011	150,000 (0.2%)

Notes:

- (1) Member of the Audit Committee.
- (2) Member of the Compensation and Governance Committee.
- (3) Member of the Reserves and Environment Committee.
- (4) Mr. Gossen resigned as Vice President, Finance, Chief Financial Officer and Corporate Secretary of the Corporation on August 31, 2009 but remained a director.
- (5) C. James Cummings was a director of the Corporation until his resignation effective July 17, 2009.
- (6) On November 2, 2010, the Corporation issued 1,400,000 Common Shares at a price of \$0.05 per share to Rembrandt Resources Ltd. in satisfaction of accounting fees owing to its principal, who is Vecta's Controller. The liability accumulated over a 14-month period as a result of the Corporation's 2009 cash conserving actions that significantly reduced cash compensation.
- (7) On January 20, 2011, the board of directors of the Corporation appointed Ms. Zuber to the position of Vice President Finance and Chief Financial Officer.

As of December 31, 2010, the directors and officers of the Corporation, as a group, beneficially owned or controlled, indirectly or directly, 5,963,233 Common Shares, representing 8.1% of the issued and outstanding Common Shares. As of the date hereof, the directors and officers of the Corporation, as a group, beneficially owned or controlled, indirectly or directly 6,113,233 Common Shares, representing 8.3% of the issued and outstanding Common Shares.

7.1 Orders

To the knowledge of management of the Corporation, other than as disclosed herein, no director or executive officer as at April 29, 2011, or was within 10 years before April 29, 2011, a director, chief executive officer or chief financial officer of any company (including the Corporation), that (a) was subject to an order that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or (b) was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer. For the purposes hereof, "order" means (a) a cease trade order, (b) an order similar to a cease trade order, or (c) an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days.

7.2 Bankruptcies

Other than disclosed herein, no director or executive officer of the Corporation is, as of April 29, 2011, or has been, within 10 years before April 29, 2011, a director or executive officer of any company that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal to under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than Charles Selby, who was the Chairman and a director of Wellpoint Systems Inc. ("Wellpoint") from April 2006 to January 2011. Wellpoint was placed into receivership by two of its lenders on January 31, 2011. Wellpoint is a TSXV listed company, supplying software to the energy industry in Canada, the US and internationally.

No director or executive officer of the Corporation has, within 10 years before April 29, 2011 become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold its assets.

7.3 Penalties and Sanctions

To the knowledge of management of the Corporation, no director or executive officer or shareholder holding a sufficient number of common shares to affect materially the control of the Corporation, has been subject to any penalties or sanctions imposed by a court relating to Canadian securities legislation or by a Canadian securities regulatory authority or has entered into a settlement agreement with a Canadian securities regulatory authority, or has been subject to any other penalties or sanctions imposed by a court or regulatory body that would be likely to be considered important to a reasonable investor making an investment decision.

7.4 Conflicts of Interest

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

interests of the Corporation. Certain of the directors of the Corporation have either other employment or other business or time restrictions placed on them and accordingly, these directors of the Corporation will only be able to devote part of their time to the affairs of the Corporation.

PART 8: AUDIT COMMITTEE

The purpose of the Corporation's audit committee (the "**Audit Committee**") is to provide assistance to its board of directors in fulfilling its legal and fiduciary obligations with respect to matters involving the accounting, auditing, financial reporting, internal control and legal compliance functions of the Corporation. It is the objective of the Audit Committee to maintain a free and open means of communications among the board of directors, the independent auditors and the senior management of the Corporation.

The full text of the Audit Committee's charter is attached hereto as Schedule "A" and forms part of this Annual Information Form.

8.1 Composition of the Audit Committee

The Audit Committee is comprised of Darrell Zakreski (Chair), Kenneth West and Stuart Gossen. Each of the members are independent within the meaning of section 1.4 of National Instrument 52-110 *Audit Committees* ("**NI 52-110**"). Each of the members is financially literate within the meaning of section 1.6 of NI 52-110.

8.2 Relevant Education and Experience

The following relevant education and experience of the members of the Audit Committee have been used in assessing their financial literacy:

Darrell Zakreski has 30 years of private business experience both in personnel recruiting and oil and gas operations, as well as commercial real estate development in Calgary, Alberta, and Victoria, British Columbia. His experience covers domestic and international operations.

Kenneth West has been employed in the oil and gas industry for 37 years and has a Bachelor of Science, and Ph.D. in Geophysics. He held senior executive positions in a major oil and gas company and prior to his retirement in 2000, he was Senior Vice President of Exploration and Strategic Planning for Crestar Energy Inc. and President and Chief Operating Officer of Crestar Energy International.

Stewart Gossen has been employed in the oil and gas industry for over 35 years both domestically and internationally. He has a Bachelor's degree in Economics and Masters of Business Administration. He has held senior executive positions in two major energy companies and prior to joining the Corporation as Vice President, Finance and Chief Financial Officer, he was Vice President, Business Development with Enbridge Inc. Mr. Gossen is currently a director of several companies as well as a director, Executive Vice President and Chief Financial Officer of Source Rock Energy Partners Inc.

8.3 Pre-Approval Policies and Procedures

The Audit Committee pre-approves engagements for non-audit services provided by the external auditors or their affiliates, together with estimated fees and potential issues of independence.

8.4 Audit Committee Oversight

At no time since the commencement of the Corporation's most recently completed financial year was a recommendation of the Audit Committee to nominate or compensate an external auditor (currently, Meyers Norris Penny LLP, Chartered Accountants) not adopted by the board of directors of the Corporation.

8.5 Reliance on Certain Exemptions

Since the effective date of NI 52-110, the Corporation has not relied on the exemptions contained in sections 2.4 or 8 of NI 52-110. Section 2.4 provides an exemption from the requirement that the audit committee must pre-approve all non-audit services to be provided by the auditor, where the total amount of fees related to the non-audit services are not expected to exceed 5% of the total fees payable to the auditor in the fiscal year in which the non-audit services were provided. Section 8 permits a company to apply to a securities regulatory authority for an exemption from the requirements of NI 52-110, in whole or in part.

The Corporation is also relying on the exemption set out in section 6.1 of NI 52-110 with respect to compliance with the requirements of Part 3 (Composition of the Audit Committee) and Part 5 (Reporting Obligations) of NI 52-110.

8.6 External Auditor Service Fees (By Category)

Year Ended	Auditor	Audit Fees	Audit Related Fees	Tax Fees	All Other Fees
December 31, 2010	Meyers Norris Penny LLP	\$35,000			\$46,782.22 ⁽¹⁾
December 31, 2009	Grant Thornton LLP	\$59,507	-	\$2,288	\$1,840 ⁽²⁾
December 31, 2008	Grant Thornton LLP	\$67,195	-	-	\$53,736 ⁽³⁾

Notes:

- (1) Fees include \$7,500.00 for financial review for the prospectus, \$15,000.00 for financial review of the third quarter of 2010, and \$3,500.00 for IFRS Phase I Advisory Services, provided by Meyers Norris Penny LLC. Also included is \$3,013.50 for 2010 Audit Planning, \$6,348.64 for financial review of documents incorporated by reference in the prospectus and \$11,420.06 for review of preliminary prospectus and documents incorporated by reference and the preparation of responses to due diligence questions related to the prospectus by Grant Thornton LLP.
- (2) \$1,840 represents auditor fees related to the wind-up of Old Vecta.
- (3) \$53,736 represents auditor fees related to the acquisition of Old Vecta.

PART 9: DESCRIPTION OF SHARE CAPITAL

The Corporation is authorized to issue an unlimited number of Common Shares and an unlimited number of preferred shares without nominal or par value. As at April 29, 2011, there were 73,620,009 Common Shares and nil preferred shares issued and outstanding. The Common Shares have the following rights, privileges, restrictions and conditions:

the right to receive notice of and to attend and vote at all meetings of holders of Common Shares except meetings of the holders of another class of shares, with each Common Share entitling the holder thereof to one vote;

subject to the preferences accorded to the holders of the preferred shares, the holders of Common Shares are entitled to receive such dividends as may be deemed thereon by the board of directors of the Corporation from time to time; and

in the event of the liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, the holders of Common Shares are entitled to receive *pro rata* all of the assets remaining for

distribution after the payment to the holders of the preferred shares, in accordance with the preference on liquidation, dissolution or winding up accorded to the holders of the preferred shares.

The preferred shares have the following rights, privileges, restrictions and conditions:

- (1) the board of directors of the Corporation may issue the preferred shares in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the board of directors;
- (2) the board of directors of the Corporation may fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of preferred shares including (a) the amount, if any, specified as being payable preferentially to such series on a distribution of capital of the Corporation, (b) the extent, if any, of further participation in a distribution of capital, (c) voting rights, if any, and (d) dividend rights (including whether such dividends be preferential, or cumulative or non-cumulative), if any;
- (3) in the event of the liquidation, dissolution or winding up of the Corporation, whether voluntary or involuntary, the holders of each series of preferred shares are entitled, in priority to the holders of Common Shares, on a distribution of capital, to be paid rateably with the holders of each other series of preferred shares the amount, if any, specified as being payable preferentially to the holders of such series on a distribution of capital of the Corporation; and
- (4) the holders of each series of preferred shares are entitled, in priority to the holders of Common Shares, with respect to the payment of cumulative dividends, to be paid rateably with the holders of each other series of preferred shares, the amount of cumulative dividends, if any, specified as being payable preferentially to the holders of such series.

9.1 Dividends

The Corporation has not declared or paid any dividends on the Common Shares. Any decision to pay dividends on such shares in the future will be made by its board of directors on the basis of the Corporation's earnings, financial requirements and other conditions existing at such future time. It is the current intention of the Corporation not to pay any dividends on the Common Shares in the near future.

On August 22, 2007, the Corporation announced the distribution of 6,997,507 shares of Shelton to its shareholders as partial consideration for the sale of Zhoda. Each shareholder of record on August 17, 2007 received one share of Shelton for every 5.178 Common Shares held. Those shares were a distribution of the stated capital of Common Shares, and was not deemed a dividend under the *Income Tax Act* (Canada) (the "**Tax Act**") as management believed the exception contained in proposed subsection 84(4.1) of the Tax Act applied to the distribution.

9.2 Market For Securities

The following table sets out the price range for, and trading volume of, the Common Shares as reported by the TSXV for the periods indicated:

	Trading Price		Volume Traded
	High	Low	# of shares
2010			
January	\$0.040	\$0.015	2,701,313
February	\$0.035	\$0.020	1,868,113
March	\$0.040	\$0.025	914,526
April	\$0.035	\$0.015	3,595,800
May	\$0.020	\$0.015	1,220,100

	Trading Price		Volume Traded
	High	Low	# of shares
June	\$0.020	\$0.015	445,092
July	\$0.020	\$0.015	969,300
August	\$0.025	\$0.020	175,546
September	\$0.020	\$0.010	413,661
October	\$0.025	\$0.015	860,721
November	\$0.195	\$0.020	43,918,414
December	\$0.240	\$0.105	15,360,357
2011			
January	\$0.22	\$0.15	7,699,051
February	\$0.26	0.12	9,109,438
March	\$0.31	\$0.15	11,452,939
April	\$0.20	\$0.12	1,740,877

9.3 Escrowed Securities

On November 2, 2010, the Corporation issued 1,400,000 Common Shares at \$0.05 per share to Rembrandt Resources Ltd. in satisfaction of accounting services for a 14-month period as a result of the Corporation's 2009 cash conserving actions. Such Common Shares were subject to a four-month hold period under the TSXV policies.

PART 10: INFORMATION CONCERNING THE OIL AND NATURAL GAS INDUSTRY

Companies operating in the oil and natural gas industry are subject to extensive controls and regulations imposed by various levels of government. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and natural gas industry. It is not expected that any of such controls or regulations would affect the operations of the Corporation in a manner materially different than they would affect other companies of similar size in the oil and natural gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted.

10.1 Pricing and Marketing

Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with a competitive open market setting the price of oil. The price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving any such export has been obtained from the National Energy Board (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

In Canada, the price of natural gas results from transactions between buyers and sellers in an open, transparent market environment. 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 export contracts in excess of two years must continue to meet certain criteria prescribed by the NEB and the government of Canada. As is the case with oil, natural gas exports for a term of less than two years must be made pursuant to an NEB order, or, in the case of exports for a longer duration, pursuant to an NEB

licence and Governor in Council approval. The price received by the Corporation depends, in part, on the prices of competing natural gas and other substitute fuels, access to downstream transportation, distance to markets, length of the contract term, weather conditions, the supply and demand balance and other contractual terms.

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

10.2 The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the U.S. and Mexico became effective. NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed provided that the restrictions are justified under certain provisions of the General Agreement on Tariffs and Trade then only if the export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of the energy resource (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes, to minimize disruption of contractual arrangements and to avoid undue influence with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

10.3 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, NGLs, 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 make annual rental payments, currently at a rate of \$3.50 per hectare, and 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" (the "**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 that were intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors; specifically, the maximum royalty rates for conventional oil and natural gas production will be decreased effective for the January 2011 production month and certain temporary incentive programs currently in place will be made permanent.

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 NRF, 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 range from 0% to 50%, an increase from the previous maximum rates of 30% to 35% depending on the vintage of the oil, and rate caps are set at \$120/bbl. Effective January 1, 2011, the maximum royalty payable under the NRF is reduced to 40%.

Royalty rates for natural gas under the NRF 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 range from 5% to 50%, an increase from the previous maximum rates of 5% to 35%, and rate caps are set at \$17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 36%.

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. 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 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 \$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 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 five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) 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 will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31,

2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

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 bbls 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, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

10.4 Land Tenure

Crude oil and natural gas located in the western Canadian 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 from two years 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 licence.

In Alberta, the NRF includes a policy of "shallow rights reversion", which provides, for the first time in western Canada, for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licences. For leases and licences issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or licence. 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 licences 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.

10.5 Environmental Regulation

Companies operating in the oil and natural gas industry are subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in the imposition of fines or issuance of clean-up orders. Under the *Environmental Protection and Enhancement Act* (Alberta), changes in these regulations have had an incremental effect on the cost of conducting operations in Alberta.

The Corporation is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and expense nature, as a result of the increasingly stringent laws relating to the protection of the environment. The Corporation's internal procedures are designed to ensure that the environmental aspects of new developments are taken into account prior to proceeding. The Corporation believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

10.6 Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol (the "**Kyoto Protocol**"), which requires a reduction in greenhouse gas 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 greenhouse gas emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark from December 6 to 18, 2009 (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing greenhouse gas emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the Copenhagen Accord does not establish binding greenhouse gas emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

In response to the Copenhagen Accord, the Government of Canada has recently indicated that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous federal government policy documents which are discussed below.

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 greenhouse gases 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**"). 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 recently 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 greenhouse gas emissions regulation. The approach of the United States is expected to include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the Updated Action Plan.

In the absence of United States federal climate legislation permitting a cap and trade program in the United States, the Environmental Protection Agency (the "**EPA**") is proposing a number of standards-based regulatory initiatives to regulate greenhouse gas emissions, including the regulation of greenhouse gas emissions from large stationary sources. The EPA promulgated the Mandatory Reporting of Greenhouse Gases Rule (the "**Rule**") on December 29, 2009, which rule requires reporting from large sources and suppliers. The EPA is proposing to add new sources by way of amendments to the Rule that will include petroleum and natural gas facilities emitting 25,000 metric tonnes or more of CO₂ equivalents per year.

As a result of the foregoing, many provisions of the Updated Action Plan, as described below, are expected to be significantly modified. The stated goal of the Updated Action Plan, as currently drafted, is to reduce greenhouse gas emissions to 20% below 2006 levels by 2020 and 60% to 70% below 2006 levels by 2050. As noted above, the goal has now been modified by the Government of Canada. 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 will be applied 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 three-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 CO₂ equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO₂ 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 govern 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: Technology Fund contributions, offset credits, clean development credits and credits for early action. 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 CO₂ equivalent for the 2010-12 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 greenhouse gas 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 Updated Action Plan may be significantly changed if, as a result of the Canada/U.S. Clean Energy Dialogue, Canada adopts targets and regulatory tools similar to those adopted in the United States in order to regulate the emission of greenhouse gases.

Under section 46(1) of the *Canadian Environmental Protection Act, 1999*, the Government of Canada requires mandatory reporting of greenhouse gas emissions. Notices are published in the *Canada Gazette* setting out the greenhouse gases, their respective global warming potential and the criteria for reporting. The "*Canada Gazette* Notice for 2009 Emissions" sets out the requirement for facilities that exceed the 50,000-metric-tonne CO₂-equivalent greenhouse gas threshold to report their annual emissions on or before June 1, 2010.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on July 1, 2007, 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 greenhouse gases per year must comply with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Existing Facilities" and "New Facilities". Existing Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2008 or that have completed eight or more years of commercial operation. Existing Facilities were required to reduce their emissions intensity by March 31, 2008 by 12% from a baseline established by their average emissions intensity between 2003

and 2005. New Facilities are defined as facilities that completed their first year of commercial operation subsequent to December 31, 2008, 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 also required to reduce their emissions intensity by 12%, but this target is based on the emissions intensity of the facility in its third year of commercial operation and does not apply during the first three years of operation of the New Facility. Unlike the Updated Action Plan, the CEEMA does not contain any provision for continuous annual improvements beyond the 12% emissions intensity required.

The CEEMA contains compliance mechanisms similar to those in 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 CO₂ equivalent. Unlike the Updated Action Plan, CEEMA 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 CEEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

PART 11: RISK FACTORS

The holding of securities in the Corporation should be considered highly speculative due to the nature of the Corporation's business and the present stage of its development. The following is a summary of certain risk factors relating to the activities of the Corporation and the ownership of the Corporation's securities which should be carefully considered before making an investment decision relating to the Corporation's securities.

11.1 Volatility of Oil and Gas Prices and Markets

The Corporation's financial performance and condition are substantially dependent on the prevailing prices of oil and natural gas which are unstable and subject to fluctuation. Fluctuations in oil or natural gas prices could have an adverse effect on the Corporation's operations and financial condition and the value and amount of its reserves. Prices for crude oil fluctuate in response to global supply of and demand for oil, market performance and uncertainty and a variety of other factors which are outside the control of the Corporation including, but not limited, to the world economy and OPEC's ability to adjust supply to world demand, government regulation, political stability and the availability of alternative fuel sources. Natural gas prices are influenced primarily by factors within North America, including North American supply and demand, economic performance, weather conditions and availability and pricing of alternative fuel sources. In addition, the marketability of the production depends upon the availability and capacity of gathering systems and pipelines, the effect of federal and provincial regulation on such production and general economic conditions. All of these factors are beyond the control of the Corporation.

Prices varied considerably throughout 2010. Decreases in oil and natural gas prices typically result in a reduction of the Corporation's net production revenue and may change the economics of producing from some wells, which could result in a reduction in the volume of the Corporation's reserves. Any substantial declines in the prices of crude oil or natural gas could also result in delay or cancellation of existing or future drilling, development or construction programs or the curtailment of production. All of these factors could result in a material decrease in the Corporation's net production revenue, cash flows and profitability and have a material adverse effect on the Corporation's operations, financial condition, proved reserves and the level of expenditures for the development of its oil and natural gas reserves, causing a reduction in its oil and gas acquisition and development activities. In addition, bank borrowings available to the Corporation will in part be determined by the company's borrowing base. A sustained material decline in prices from historical

average prices could further reduce such borrowing base, therefore reducing the bank credit available and could require that a portion of its bank debt be repaid.

From time to time the Corporation has and may in the future 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.

11.2 Current Global Financial Markets

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. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

11.3 Capital Markets

As a result of the weakened global economic situation, the Corporation, along with all other oil and gas entities, may have restricted access to capital, bank debt and equity, and is likely to face increased borrowing costs. Although the Corporation's business has not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of funds generated from operations, borrowings and possible future equity sales, the Corporation's ability to make such capital expenditures will be dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and the Corporation's securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected as a result.

If funds generated from operations are lower than expected or capital costs for these projects exceed current estimates, or if the Corporation incurs major unanticipated expenses related to development or maintenance of its existing properties, it will be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

11.4 Development of Additional Reserves

The Corporation's future success is dependent upon its ability to explore, develop or acquire additional oil and natural gas reserves that are economically recoverable at attractive acquisition prices. Except to the extent that the Corporation conducts successful activities or acquires properties containing proved reserves, or both, the proved reserves and production will generally decline as reserves are produced. If prevailing oil and natural gas prices were to increase significantly, the Corporation's costs to add reserves could be expected to increase. The drilling of oil and natural gas wells involves a high degree of risk, especially the risk

of a dry hole or of a well that is not sufficiently productive to provide an economic return on the capital expended to drill the well.

Exploitation and development risks are due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploitation efforts in areas in which the Corporation has existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods and controlling costs to maximize returns. Advanced oil and natural gas related technologies such as three dimensional seismography, reservoir simulation studies and horizontal drilling may, where appropriate, be used by the Corporation to improve its ability to find, develop and produce oil and natural gas.

11.5 Title

Although satisfactory title reviews of the Corporation's properties are conducted in accordance with industry standards, those title reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Corporation to a property.

11.6 Environmental Concerns

The operation of oil and natural gas wells involves a number of natural hazards which may result in blowouts, environmental damage or other unexpected or dangerous conditions resulting in liability to the Corporation and possibly liability to third parties. Companies operating in the oil and natural gas industry are subject to extensive environmental regulation which provides for restrictions and prohibitions on releases or emissions of various substances produced in association with certain oil and natural gas industry operations. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. A breach of such legislation may result in fines or the issuance of clean-up orders. See "Information Concerning the Oil and Natural Gas Industry – Environmental Regulation". The Corporation will make reasonable provision for well abandonment and reclamation where appropriate; however, there can be no assurance that such provision will be sufficient to satisfy all such obligations. No sinking fund or reserve will be established for the purpose of site reclamation or abandonment costs.

11.7 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 controls and regulations may be amended from time to time. See "Information Concerning the Oil and Natural Gas Industry". Governments may regulate or intervene with respect to prices, 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.

11.8 Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to establish legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets slightly. 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 greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with legislation in Canada regulating emissions of greenhouse gases. The future implementation or modification of greenhouse gas regulations 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 greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Information Concerning the Oil and Natural Gas Industry – Climate Change Regulation".

11.9 Reserves Estimates

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. 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 consultants have used both constant and forecast price and cost estimates in calculating reserves quantities for the Corporation's reserves. 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 therefrom will vary from the estimates contained in the applicable engineering reports. The reserves reports are based in part on the assumed success of activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in the applicable engineering reports will be reduced to the extent that such activities do not achieve the level of success assumed in the engineering reports.

11.10 Purchase of Reserves

Acquisitions of resource issuers and resource assets by the Corporation will be based on engineering and economic assessments made by management and reviewed by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other governmental levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Corporation. In particular, changes in the prices of and markets for oil and natural gas from those anticipated at the time of making such assessments will affect the value of the Corporation's securities. In addition, all such assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than anticipated.

11.11 Depletion of Reserves

The Corporation's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on the Corporation's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are exploited, and from time to time production declines can be severe under certain conditions.

To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired.

There can be no assurance that the Corporation will be successful in developing or acquiring additional reserves on terms that meet the Corporation's investment objectives.

11.12 Foreign Exchange

Operating costs incurred by the Corporation are generally paid in Canadian dollars. World oil 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 that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact the Corporation's net production revenue. To the extent that the Corporation has engaged or will in the future engage in risk management activities related to commodity prices and foreign exchange rates, through entry into oil and natural gas price hedges and forward foreign exchange contracts or otherwise, the Corporation will be subject to unfavourable price changes and credit risks associated with the counter parties with which it contracts.

11.13 Potential Conflicts of Interest

Some of the directors of the Corporation are also directors of other oil and natural gas companies, which may from time to time be in competition with the Corporation for working interest partners, property acquisitions, or other limited resources. Where required by law, appropriate disclosure of such conflicts will be made by the applicable directors. In particular, the Corporation follows the provisions of the ABCA. These provisions state that in the event that a director has an interest in a contract or proposed contract or agreement, such director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise permitted by the ABCA.

11.14 Competition

The oil and natural gas industry is intensely competitive and the Corporation will compete for joint venture partners, capital, reserves acquisitions and skilled industry personnel with a substantial number of other companies which have greater resources. Many such companies not only explore for and produce oil and natural gas, but also carry on refining operations and market petroleum and other products on a worldwide basis and as such have greater and more diverse resources upon which to draw. There is also competition between the oil industry and other industries with respect to the supply of energy and fuel to industrial, commercial and individual customers.

11.15 Operating Risks

The oil and natural gas business involves a variety of operating risks, including the risk of fire, explosions, blowouts and encountering formations with abnormal pressure and oil spills, the occurrence of any of which could result in substantial losses to the Corporation. The Corporation will maintain insurance against some, but not all, of these risks, in amounts which meet or exceed standard industry practice. There can be no assurance that any insurance will continue to be available at premium levels that justify its purchase or whether insurance will be available at all.

Continuing production from the Corporation's properties, and to some extent the marketing of production therefrom, are dependent upon the ability of the operator of such properties. To the extent that the operator of a property fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent or experiences cash flow problems.

11.16 Changes in Legislation

There can be no assurance that income tax laws, other laws or government incentive programs relating to the oil and gas industry, will not be changed in a manner which will adversely affect the Corporation. There can be no assurance that tax authorities having jurisdiction will agree with how the Corporation calculates its income for tax purposes or that such tax authorities will not change their administrative practices to the detriment of the Corporation.

11.17 Enforcement of Operating Agreements

Operations of the wells located on properties not operated by the Corporation are generally governed by operating agreements that typically require the operator to conduct operations in a good and workmanlike manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to the Corporation.

11.18 Substantial Capital Requirements

The Corporation anticipates that it will make 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, the Corporation may have limited ability to expend the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. Moreover, future activities may require the Corporation to alter its capitalization significantly, including transactions involving the issuance of securities, which may be dilutive. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's financial condition, results of operations or prospects.

11.19 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 available on terms acceptable to the Corporation.

11.20 Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Corporation's debt levels above industry standards. 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 in the future on a timely basis to take advantage of business opportunities that may arise.

11.21 Insurance

The Corporation's involvement in the exploration for and development of oil and gas properties may result in the Corporation becoming subject to liability for pollution, blow-outs, property damage, personal injury or other hazards. Although the Corporation intends to obtain insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not, in all circumstances be 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 such 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, could have a material adverse effect on the Corporation's financial position, results of operations or prospects.

11.22 Reliance on Operators and Key Employees

To the extent the Corporation is not the operator of its oil and gas properties, the Corporation will be dependent on such operators for the timing of activities related to such properties and will largely be unable to direct or control the activities of the operators. In addition, the success of the Corporation will be largely dependent upon the performance of its management and key employees. The Corporation does not have any key man insurance policies, and therefore there is a risk that the death or departure of any member of management or any key employee could have a material adverse effect on the Corporation.

11.23 Delays in Business Operations

In addition to the usual delays in payments by purchasers of oil and natural gas to the Corporation or to the operators, and the delays by operators in remitting payment to the Corporation, payments between these parties may be delayed due to restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, adjustment for prior periods, or recovery by the operator of expenses incurred in the operation of the properties. Any of these delays could reduce the amount of cash flow available for the business of the Corporation in a given period and expose the Corporation to additional third party credit risks.

11.24 Permits and Licences

The operations of the Corporation may require licences and permits from various governmental authorities. There can be no assurance that the issuer will be able to obtain all necessary licences and permits that may be required to carry out exploration and development at its projects.

11.25 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 the Corporation's assets; however, if a claim arose and was successful, it could have an adverse effect on the Corporation and its operations.

11.26 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 potential declines in production of oil and gas of the Corporation.

11.27 Income Taxes

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

11.28 Borrowing

The Corporation's lenders have been provided with security over substantially all of the assets of the Corporation. If the Corporation becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell the Corporation's properties. The proceeds of any such sale would be applied to satisfy amounts owed to the Corporation's lenders and other creditors and only the remainder, if any, would be available to the Corporation.

11.29 Acquisition Risk

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

Additionally, the oil and gas property acquisition business is highly competitive, and is populated with many companies, large and small, with the capital and expertise to evaluate, purchase, and exploit producing and non-producing opportunities. Even with capital and experience, the industry risks of drilling dry holes and cost overruns are significant. Environmental compliance is an increasingly complex and costly burden to entry for many new exploration areas, and often times, and even if permits are obtained, they are sufficiently restrictive that a property cannot be explored to its full potential. The Corporation may not be able to locate acquisition opportunities, or finance those that the Corporation can. The Corporation offer no assurance that its entry into this business activity will be successful.

11.30 Third Party Credit Risk

The Corporation is or 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 could have a material adverse effect on the Corporation and its cash flow from operations.

PART 12: LEGAL PROCEEDINGS AND REGULATORY ACTIONS

12.1 Legal Proceedings

To the knowledge of the management of the Corporation, there are no outstanding legal proceedings material to the Corporation to which the Corporation is a party or in respect of which any of its properties are subject, nor are there any such proceedings known to be contemplated.

12.2 Regulatory Actions

To the knowledge of management of the Corporation, no penalties or sanctions have been imposed by a court relating to securities legislation or by a securities regulatory body or by any other court or regulatory

body that would likely be considered important to a reasonable investor in making an investment decision, nor have any settlement agreements been entered into by the Corporation with a court relating to securities legislation or with a securities regulatory authority during the most recently completed financial year.

PART 13: INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as set out below, none of the directors, executive officers of the Corporation, any person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of any class or series of outstanding voting securities of the Corporation, nor any associate or affiliate of the foregoing persons had any material interest, direct or indirect, in any transaction during the three most recently completed financial years or during the current financial year that has materially affected or will materially affect the Corporation.

In 2009, due to low natural gas prices, the National Bank of Canada reduced the \$1.0 million credit facility to \$500,000 and the Corporation became non-compliant with its loan agreement. To remedy this, on October 29, 2009, the Corporation obtained the Secured Loans from directors of the Corporation as well as other related parties for an aggregate principal amount of \$500,000. The proceeds of the Secured Loans were used to retire the Corporation's bank loan and for other corporate purposes. The Secured Loans were scheduled to mature on October 1, 2010 and had an interest rate of 15% per annum. There was no provision for early redemption by the Corporation. The holders of the Secured Loans were entitled to receive security equivalent to the security held by the National Bank of Canada, being all the Corporation's interests in petroleum and natural gas rights and other assets of the Corporation.

On October 1, 2010, holders of the Secured Loans agreed to extend the maturity date to November 1, 2010 if the Corporation entered into a letter of intent to negotiate a business transaction. The directors of the Corporation further agreed that, upon execution of the letter of intent with respect to a joint venture, the maturity date would be further extended to February 1, 2011 to allow for completion of documents and financing. On November 2, 2010, the Corporation signed a letter of intent with the Joint Venture Partner to enter into a 50/50 joint venture to participate in the Exshaw/Bakken light oil resource play in northern Montana.

On November 2, 2010, the Corporation's Controller agreed to convert his consulting fees of \$70,000 into Common Shares at a conversion price of \$0.05 per share. In connection with this agreement, through his personal holding corporation, Rembrandt Resources Ltd., the Controller of the Corporation agreed to accept 1,400,000 Common Shares at a deemed value of \$0.05 per Common Share in lieu of a portion of his salary for the 14-month period from May 1, 2009 to June 30, 2010.

On January 20, 2011, the holders of the Secured Loans of the Corporation agreed to further extend the maturity date of the Secured Loans to April 1, 2011 to allow for completion of documents and financing pertaining to the joint venture.

On March 24, 2011, the Secured Loan holders of the Corporation agreed to further extend the maturity date of the Secured Loans to April 29, 2011 to complete financing and other requirements pertaining to the joint venture agreement.

13.1 Transfer Agent and Registrar

The transfer agent and registrar for the Common Shares is Equity Transfer & Trust Company, whose offices are located at Suite 850, 505 – 3rd Street S.W., Calgary, Alberta T2P 3E6.

13.2 Material Contracts

Other than the Secured Loan Agreements dated October 19, 2009 between the Corporation and each of John Beecherl, Fred Callaway, Thomas Coffman, Allen Gilmer, Stewart Gossen, David McKenzie, David Powell, Charles Selby and Darrell Zakreski and the JV Agreement (copies of which are available under the Corporation's SEDAR profile at www.sedar.com), the Corporation did not enter into any material contracts outside the ordinary course of business within the most recently completed financial year or prior thereto that are still in effect. See "Business of the Corporation – Relevant Three Year History" and "Business of the Corporation – Recent Developments".

13.3 Interest of Experts

Sproule prepared the Reserve Report referred to in this Annual Information Form. As of April 29, 2011, the partners, employees and consultants of Sproule who participated in or who were in a position to directly influence the preparation of the Reserve Report did not hold any of the securities of the Corporation.

Meyers Norris Penny LLP has confirmed that it is independent of the Corporation in accordance with the relevant rules and related interpretation prescribed by the Institute of Chartered Accountants of Alberta.

13.4 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, if applicable, is contained in the Corporation's information circular dated May 19, 2010. Additional financial information is also provided in the Corporation's consolidated financial statements and MD&A for the year ended December 31, 2010.

SCHEDULE A – AUDIT COMMITTEE CHARTER**Purpose**

The overall purpose of the Audit Committee of the Board of Directors (the "**Board**") of Vecta Energy Corporation (the "**Corporation**") is to ensure that the Corporation's management has designed and implemented an effective system of internal financial controls for, and to review and report on the integrity of the financial statements of the Corporation. The Committee also will review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and disclosure of material facts with respect to such matters. As part of this mandate, the Committee shall take all necessary steps so as to ensure compliance by the Corporation with all laws and regulatory policies, rules, regulations and instruments pertaining to the Corporation from time to time (the "**Applicable Laws**").

Composition, Procedures and Organization

1. The Committee shall consist of not less than three members of the Board of Directors of the Corporation, each of whom
 - (a) must meet any independence tests; and
 - (b) must satisfy any financial literacy or other competency standards set out under Applicable Laws.
2. The Board, at its organizational meeting held following each Annual General & Special Meeting of the shareholders of the Corporation shall appoint the members of the Committee for the ensuing year and shall appoint one of those members to be Chairman. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.
3. The Secretary of the Corporation shall be the secretary of the Committee.
4. The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.
5. The Committee shall have access to such officers and employees of the Corporation and to the Corporation's auditors and to such information respecting the Corporation as the Committee considers necessary or advisable in order to perform its duties and responsibilities.
6. Meetings of the Committee shall be conducted as follows:
 - (a) The Committee shall meet at least four times annually as requested by the Chairman. The Corporation's external auditors or any member of the Committee also may request a meeting of the Committee.
 - (b) The Chief Executive Officer and the Chief Financial Officer of the Corporation shall be invited to attend all meetings of the Committee, except in-camera sessions or private sessions with the external auditors.

Duties and Responsibilities

1. The overall duties and responsibilities of the Committee shall include:
 - (a) assisting the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and approving the Corporation's annual and quarterly consolidated financial statements;
 - (b) establishing and maintaining a direct line of communication with the Corporation's external auditors and assessing their performance; and

- (c) reporting regularly to the Board on the fulfillment of the duties and responsibilities of the Committee.
8. The duties and responsibilities of the Committee as they relate to the external auditors shall include:
- (a) recommending to the Board a firm of external auditors to be engaged by the Corporation;
 - (b) reviewing and approving the fee, scope and timing of the audit and other related services rendered by the external auditors;
 - (c) overseeing the work of the external auditor in the course of the annual audit or other services performed for the Corporation;
 - (d) reviewing the audit plan of the external auditor prior to the commencement of the audit; and
 - (e) reviewing with the external auditors, on completion of the audit:
 - (i) contents of the audit report;
 - (ii) scope and quality of the audit work performed;
 - (iii) adequacy of the Corporation's financial staff and cooperation received during the audit;
 - (iv) significant transactions outside of the normal business of the Corporation;
 - (v) significant proposed adjustments and recommendations for improving the internal accounting controls, accounting principles or management systems; and
 - (vi) significant audit findings and recommendations, and managements response thereto.
9. The Committee shall hold in-camera meetings with the external auditors at least once each year prior to the approval of the audited financial statements of the Corporation and at such other times as determined necessary or appropriate by the Committee.
10. The duties and responsibilities of the Committee as they relate to the internal control procedures of the Corporation are to:
- (a) ensure that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements and periodically assess the adequacy of those procedures;
 - (b) review the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management;
 - (c) review compliance with the policies outlined in the Corporation's Policy Manual, particularly with respect to the Authority Guidelines, Business Conduct, Disbursement of Funds, and Whistleblower Protection and recommend to the Board changes that the Committee may deem appropriate; and
 - (d) review any unresolved issues between management and the external auditors that could affect the financial reporting or internal controls of the Corporation; and periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the external auditors have been implemented.

FORM 51-101F2

SCHEDULE B: REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR**To the Board of Directors of Vecta Energy Corporation (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 attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2010, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
Sproule	Evaluation of the P&NG Reserves of Vecta Energy Corporation as of December 31, 2010, prepared in March 2011	Canada		966	Nil	966
Total			Nil	966	Nil	966

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented in accordance with the consistent application of the COGE Handbook.
6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring after its preparation date.
7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited

Calgary, Alberta

March 21, 2011

Original signed by Robert N. Johnson
Robert N. Johnson, P.Eng.
Vice-President, Engineering and Director

Original signed by David M. Shewchuk, C.E.T.
David M. Shewchuk, C.E.T.
Senior Petroleum Engineering Technician

Original signed by Alec Kovaltchouk, P.Geol.
Alec Kovaltchouk, P.Geol.
Manager, Geoscience and Associate

Original signed by Harry J. Helwerda, P.Eng., FEC
Harry Helwerda, P.Eng.
Executive Vice-President and Director

FORM 51 – 101F3

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

This is the form referred to in item 3 of section 2.1 of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (“NI 51-101”).

1. Terms to which a meaning is ascribed in *NI 51-101* have the same meaning in this form.
2. The report referred to in item 3 of section 2.1 of *NI 51-101* must in all material respects be as follows:

**Report of Management and Directors
on reserves Data and Other Information**

Management of Vecta Energy Corporation (“Vecta”) is responsible for the preparation and disclosure of information with respect to the Company’s oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company’s reserves data. The report of the independent qualified reserves evaluator or auditor is presented below and will be filed with securities regulator authorities concurrently with this report.

The Reserves Committee of the board of directors of the Company has:

- a) reviewed the Company’s procedures for providing information to the independent qualified reserves evaluator or auditor;
- b) met with the independent qualified reserves evaluator or auditor to determine whether any restrictions affected the ability of the independent qualified reserves evaluator or auditor to report without reservation and, in the event of a proposal to change the independent qualified reserves evaluator or auditor to inquire whether there had been disputes between the previous independent qualified reserves evaluator or auditor and management; and
- c) reviewed the reserves data with management and the independent qualified reserves evaluator or auditor.

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

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

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

'signed'

Thomas D. Coffman, President & CEO

'signed'

Diane Zuber, Vice President Finance & CFO

'signed'

Fred Callaway, Director

'signed'

Stewart Gossen, Director

DATED at the City of Calgary, in the Province of Alberta, this 2nd day of May, 2011.