Vero ENERGY INC.

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2011

March 30, 2012

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ABBREVIATIONS

Oil and Natural Gas Liquids

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

Natural Gas

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

Other

AECO	A natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
ARTC	Alberta Royalty Tax Credit
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
BOE/d	barrel of oil equivalent per day
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
$000'S	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Disclosure provided herein in respect of BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

CONVERSIONS

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

CERTAIN DEFINITIONS

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

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

"**AIF**" means this annual information form of the Corporation for the year ended December 31, 2011;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means the common shares in the capital of the Corporation;

"**Disposition Assets**" means the natural gas assets of the Corporation disposed of pursuant to the 2012 Gas Asset Sale Transaction;

"**Gas Asset Sale Agreement**" means the asset purchase and sale agreement among Vero and the purchaser thereto dated as of January 2, 2012, pursuant to which Vero divested of the Disposition Assets;

"**2012 Gas Asset Sale Transaction**" means the divestiture by the Corporation of the Disposition Assets for gross proceeds of approximately $209 million, before closing adjustments, which transaction was completed on January 31, 2012;

"**Gross**" means:

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

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

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

"**Net**" means:

(a) in relation to the Corporation's interest in production and reserves, the Corporation's working interest (operating and non-operating) share after deduction of royalty obligations and including any royalty interest of the Corporation.

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

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

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

"**Remaining Assets**" means the oil and gas assets of the Corporation immediately following completion of the 2012 Gas Asset Sale Transaction;

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

"**Sproule Report**" means the report of Sproule March 5, 2012, evaluating the crude oil, natural gas liquids and natural gas reserves of the Corporation as at December 31, 2011;

"**TSX**" means the Toronto Stock Exchange; and

"**Vero**", the "**Company**" or the "**Corporation**" means Vero Energy Inc., a corporation amalgamated pursuant to the ABCA.

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

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2011.

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

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, drilling and re-completion plans, timing of drilling, re-completion and tie-in of wells, productive capacity of wells and productive capacity of wells and capital expenditures and the timing thereof, the effect of government announcements, proposals and legislation, plans regarding hedging, expected or anticipated production rates, timing of expected production increases, weighting of production between different commodities, expected commodity prices, exchange rates, production expenses, transportations costs and other costs and expenses, maintenance of productive capacity and capital expenditures and methods of financing thereof, may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Vero's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Vero believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Vero can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Vero operates; the timely receipt of any required regulatory approvals; the ability of Vero to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which Vero has an interest in to operate the field in a safe, efficient and effective manner; the ability of Vero to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Vero to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Vero operates; and the ability of Vero to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could effect Vero's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), at Vero's website (www.veroenergy.ca). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Corporation assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Corporation's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Corporation believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Corporation is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

BACKGROUND

Vero is a junior oil and natural gas company engaged in the exploration for, and the acquisition, development and production of oil and natural gas reserves primarily in western Canada.

Vero was initially formed on November 2, 2005 upon the amalgamation of Vero Energy Inc. and its then wholly-owned subsidiary, Vero Finance Corp. See "*General Development of the Business*".

Vero was amalgamated on January 1, 2010 under the ABCA with its then wholly-owned subsidiary, Vero Oil and Gas Ltd., which was incorporated under the ABCA. Vero currently has no subsidiaries.

Vero's head office is located at Suite 900, 520 – 3rd Avenue S.W., Calgary, Alberta T2P 0R3, and its registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

The Common Shares of Vero trade on the TSX under the symbol "VRO".

GENERAL DEVELOPMENT OF THE BUSINESS

History of Vero

Pre-2009

Vero has been engaged in the business of acquiring crude oil and natural gas properties and exploring for, developing and producing crude oil and natural gas in western Canada since it commenced active operations in November 2005.

Effective November 2, 2005 Vero acquired working interests in certain producing assets and undeveloped lands primarily in the Whitecourt/Edson area of west central Alberta, in addition to other minor properties (the "**Vero Initial Properties**"). At the effective date of completion of the acquisition, the Vero Initial Properties were producing approximately 850 Boe/d, comprised of 3,774 MMcf/d of natural gas and 221 Bbls/d of light oil and natural gas liquids. In addition, the Vero Initial Properties included approximately 61,600 net acres of undeveloped lands.

Funding for Vero's growth has come from a combination of cash flow from ongoing operations, the Corporation's bank facility and equity financings undertaken from time to time as described herein.

Vero has completed several material acquisitions since its inception as described below.

On February 24, 2006 Vero completed the acquisition (the "**Ledge Acquisition**") of all of the outstanding shares of a private company, Ledge Resources Limited ("**Ledge**"), on the basis of $1.90 in cash and 0.49473 of a Common Share of Vero for each share of Ledge. The previous shareholders of Ledge received a total of $18.25 million in cash and approximately 4.75 million Common Shares of Vero in exchange for all of the outstanding shares of Ledge.

Ledge was a junior oil and natural gas company that held certain producing oil and natural gas assets located primarily in the Westerose and Wilson Creek areas of Alberta, which, upon closing of the Ledge Acquisition were producing approximately 850 BOE/d, comprised of approximately 55% natural gas and 45% liquids with the liquids consisting mainly of light sweet oil. The area is characterized by year round access and the main property acquired was a light, sweet Belly River oil pool at Wilson Creek.

Following the Ledge Acquisition, the name of Ledge Resources Limited was changed to Vero Resources Inc. and on January 1, 2007 Vero completed a short form amalgamation with Vero Resources Inc. and its wholly-owned subsidiary, 1144771 Alberta Ltd., to form "Vero Energy Inc.".

On April 13, 2006 Vero completed a bought deal private placement of 2,131,150 Common Shares at a price of $6.10 per share, for aggregate gross proceeds of $13 million.

On April 5, 2007 Vero completed a bought deal private placement of 1,500,000 Common Shares at a price of $5.55 per share and 1,500,000 Common Shares issued on a "flow-through" basis at a price of $7.25 per share, for aggregate gross proceeds of $19.2 million.

On February 28, 2008 Vero completed a bought deal private placement of 1,940,000 Common Shares issued on a "flow-through" basis at a price of $9.25 per share, for aggregate gross proceeds of $17.9 million.

On April 15, 2008 Vero completed the acquisition (the "**Dorian Acquisition**") of all of the outstanding shares of a private company, Dorian Energy Inc. ("**Dorian**"), on the basis of 0.29366 of a Common Share of Vero for each share of Dorian. The previous shareholders of Dorian received an aggregate of approximately 1.8 million Common Shares of Vero in exchange for all of the outstanding shares of Dorian. Vero assumed approximately $1.8 million of Dorian net debt in connection with the Dorian Acquisition. The Dorian Acquisition had many synergies for Vero including common working interests on over 50% of the purchased production and the addition of approximately 9,500 net acres of undeveloped land in Vero's core areas of Edson, Whitecourt and Ricinus.

On May 20, 2008 Vero completed the acquisition (the "**FX Acquisition**") of a private company, FX Energy Ltd. ("**FX**"), on the basis of $0.25043 in cash for each share of FX. The previous shareholders of FX received a total of approximately $2.4 million in exchange for all of the outstanding shares of FX. In addition Vero assumed approximately $1.3 million of net debt as part of the consideration paid. Vero acquired approximately 11,400 net acres of undeveloped land and 355 thousand BOE of reserves as a result of the acquisition.

On November 10, 2008 Vero completed the acquisition (the "**Revolve Acquisition**") of all of the outstanding shares of a private company, Revolve Energy Inc. ("**Revolve**") pursuant to a plan of arrangement under the ABCA on the basis of 0.135 of a Common Share of Vero in exchange for each share of Revolve. The previous shareholders of Revolve received an aggregate of approximately 3.8 million Common Shares of Vero in exchange for all of the outstanding shares of Revolve. Vero assumed approximately $4.3 million of Revolve net debt in connection with the Revolve Acquisition. Revolve was a junior oil and natural gas company that held certain producing oil and natural gas assets located primarily in the Edson area of Alberta which, upon closing of the Revolve Acquisition, were producing approximately 800 Boe/d. In addition, Vero acquired approximately 15,000 net undeveloped acres of high working interest land, 61 km (2) of proprietary 3D seismic data, 26 km (2) of trade 3D seismic data and 1,300 km of trade 2D seismic data pursuant to the Revolve Acquisition.

In connection with the Revolve Acquisition, Revolve was amalgamated with Vero's then wholly-owned subsidiary, 1405354 Alberta Ltd., to form Vero AcquisitionCo Corp., which was subsequently dissolved effective December 9, 2008.

2009

On May 21, 2009, Vero completed a bought deal short form prospectus offering of 4,000,000 Common Shares at a price of $3.75 per share, for aggregate gross proceeds of $15 million.

On November 3, 2009, Vero completed a bought deal private placement of 2,231,700 Common Shares issued on a "flow-through" basis at a price of $5.65 per share, for aggregate gross proceeds of $12.6 million.

On December 1, 2009, Vero closed on the disposition of producing assets in the Wilson Creek/Westerose area for proceeds of $16.2 million. The aggregate production sold was approximately 295 BOE/d.

2010

In June of 2010, the Company purchased 2,598 net acres in the Cordova Embayment area of North East British Columbia for $4.1 million. The lands purchased are believed to be prospective for a shale gas development and marks Vero’s first foray into the shale gas development projects.

On November 5, 2010, Vero completed a bought deal short form prospectus offering of 1,539,000 Common Shares at a price of $6.50 per Common Share and 3,068,000 Common Shares issued on a "flow-through" basis at a price of $8.15 per share, for aggregate gross proceeds of $35.0 million.

2011

In the latter part of 2011 the Company commenced discussions to sell its deep basin natural gas production.

Recent Developments - the 2012 Gas Asset Sale Transaction

On January 3, 2012, Vero announced that it had entered into the Gas Asset Sale Agreement providing for the divestiture of natural gas assets of the Corporation to a private oil and gas company for gross proceeds of approximately $209 million, subject to closing adjustments. The 2012 Gas Asset Sale Transaction closed on January 31, 2012.

The Disposition Assets were primarily focussed in the deep basin region of West-Central Alberta and included related facilities. The Disposition Assets excluded zones from surface to base Cardium which were retained by Vero and represented estimated average daily production of approximately 7,300 Boe/d (86% natural gas) during the fourth quarter of 2011 and 25,625.2 Mboe of proved plus probable gross reserves as evaluated by Sproule effective as at December 31, 2011.

The 2012 Gas Asset Sale Transaction reflected a strategic move on the part of Vero to focus operations on its Remaining Assets, being Vero's high net back, light oil focussed Cardium resource play.

For detailed information in respect of Vero's Remaining Assets, see "*Reserves Data and Other Oil and Gas Information Following Completion of the 2012 Gas Asset Sale Transaction*".

SIGNIFICANT ACQUISITIONS

There were no significant acquisitions completed by the Corporation during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Stated Business Objectives

The business plan of Vero is to generate profitable growth, measured primarily by per share growth in production, proved reserves and cash flow from operations. To accomplish this, Vero will focus on the creation of value primarily through the generation and drilling of exploration and development prospects as well as through the exploitation and production of existing reserves. Vero targets areas and prospects that it believes could result in meaningful reserve and production additions.

Since commencing operations in November, 2005 Vero has concentrated on its core areas in Edson, Corbett and Whitecourt. These areas are characterized by multi-zone, liquids rich natural gas and light oil at medium depths. Vero also intends to pursue strategic acquisitions of oil and natural gas properties where it believes further exploration, exploitation and development opportunities exist. In late 2009, and in response to declining natural gas prices, Vero commenced an initiative to exploit its light oil Cardium prospects with activity on these lands steadily increasing throughout 2010 and 2011. Following completion of the 2012 Gas Asset Sale Transaction, Vero's activities are now currently directed predominantly towards light oil prone prospects.

Vero will internally generate exploration and development opportunities possessing medium risk and multi-zone potential and will utilize a portfolio approach in developing these opportunities to achieve a balance of risk profiles and commodity exposures with a weighting predominantly towards light oil prospects. Vero will maintain a balance between exploration, development and exploitation drilling, combined with acquisition opportunities that meet its business parameters. To achieve sustainable and profitable growth, management of Vero believes in controlling the timing and costs of its projects wherever possible. Further, to minimize competition within its geographic areas of interest, Vero strives to maximize its working interest ownership in its properties where reasonably possible. While management believes that Vero has 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, Vero gives consideration to the following criteria:

- the capital required to secure or evaluate the investment opportunity;
- the potential return on the project, if successful;
- the likelihood of success; and
- the risked return versus cost of capital.

In general, Vero uses 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 Vero may, in its discretion, but in discussion and agreement with the management of Vero, 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.

Vero's management team has a demonstrated track record of bringing together all the key components to a successful intermediate exploration and production company: strong technical skills; expertise in planning and financial controls; ability to execute on business development opportunities; and an entrepreneurial spirit that will allow Vero to effectively identify, evaluate and execute on value added initiatives.

Competitive Conditions

Companies operating in the petroleum industry must manage risks, which are beyond the direct control of company personnel. Among these risks are those associated with exploration, environmental damage, commodity prices, foreign exchange rates and interest rates.

The oil and natural gas industry is intensely competitive and Vero is required to compete with a substantial number of other corporations, which may have greater technical or financial resources. With the maturing nature of the Western Canadian Sedimentary Basin, the access to new prospects is becoming more and more competitive and complex. Management believes that Vero will be able to explore and develop new production and reserves with the objective of increasing its cash flow and reserve base.

Vero will attempt to enhance its competitive position by operating in areas where its technical personnel are able to reduce some of the risks associated with exploration, production and marketing because they are familiar with the areas of operation.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 5, 2012. The effective date of the Statement is December 31, 2011 and the preparation date of the Statement is March 5, 2012.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon evaluation by Sproule with an effective date of December 31, 2011 contained in the Sproule Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Corporation and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Corporation engaged Sproule to provide an evaluation of all of the proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. As at December 31, 2011, all of Vero's reserves are in Canada and, specifically, in the province of Alberta.

Readers should be aware that the Reserves Data set forth in this section of the AIF includes the evaluation of the Disposition Assets which were divested of by Vero pursuant to the 2012 Gas Asset Sale Transaction completed on January 31, 2012. See "*General Development of the Business – Recent Developments – 2012 Gas Asset Sale Transaction*".

The Corporation has also provided separately in this AIF detailed information in respect of reserves data and other oil and gas information related solely to the Corporation's Remaining Assets following completion of the 2012 Gas Asset Sale Transaction. See "*Reserves Data and Other Oil and Gas Information following completion of the 2012 Gas Asset Sale Transaction*".

The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Independent Qualified Reserves Evaluators in Form 51-101F2 are attached as Schedules "A" and "B" respectively, to this Annual Information Form.

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

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbls)**	**Net (Mbbls)**
Proved						
Developed Producing	1,696.7	1,472.5	57,699	50,802	1,737.6	1,125.8
Developed Non-Producing	109.9	98.7	1,458	1,320	54.2	35.2
Undeveloped	1,101.0	957.5	31,422	29,223	1,075.2	840.4
Total Proved	**2,907.5**	**2,528.6**	**90,579**	**81,346**	**2,867.1**	**2,001.4**
Probable	2,508.6	2,041.0	56,802	50,853	1,797.5	1,223.6
Total Proved Plus Probable	**5,416.1**	**4,569.6**	**147,382**	**132,199**	**4,664.6**	**3,225.0**

NET PRESENT VALUES OF FUTURE NET REVENUE ($000'S)

	Before Income Taxes Discounted At (%/year)					After Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%/Year[1]
Reserves Category	**0**	**5**	**10**	**15**	**20**	**0**	**5**	**10**	**15**	**20**	**($/Boe)**
Proved											
Developed Producing	337,480	258,968	213,090	182,991	161,672	331,689	256,787	212,195	182,599	161,491	19.26
Developed Non-Producing	15,899	11,859	9,458	7,899	6,816	11,925	9,849	8,402	7,325	6,494	26.72
Undeveloped	129,315	73,678	41,307	21,076	7,718	96,987	54,127	28,831	12,773	2,003	6.19
Total Proved	**482,695**	**344,504**	**263,855**	**211,966**	**176,206**	**440,600**	**320,763**	**249,428**	**202,697**	**169,988**	**14.59**
Probable	390,562	211,565	132,141	89,612	63,862	293,008	157,472	97,226	64,949	45,418	11.26
Total Proved Plus Probable	**873,257**	**556,070**	**385,995**	**301,578**	**240,068**	**733,608**	**478,235**	**346,654**	**267,645**	**215,407**	**13.28**

Notes:

1. Unit value before income tax is calculated based on net reserve volumes.

2. Only well abandonment costs and disconnect costs related to proved undeveloped and proved plus probable reserves on future undrilled development locations have been included in this estimate. See section entitled "*Additional Information Concerning Abandonment and Reclamation Costs*" for a comprehensive model of abandonment and reclamation costs.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS
($000'S)

Reserves Category	Revenue	Royalties	Operating Costs	Development Costs	Abandonment Costs[(1)]	Future Net Revenue Before Income Taxes	Future Income Taxes	Future Net Revenue After Future Income Taxes
Proved	1,103,927	160,327	325,207	132,274	3,424	482,695	42,095	440,600
Proved Plus Probable	1,988,782	306,565	577,336	224,849	6,775	873,257	139,649	733,608

Notes to Future Net Revenue Data Tables:

1. Only well abandonment costs and disconnect costs related to proved and proved plus probable undeveloped reserves on future undrilled development locations have been included in this estimate. No allowance was made, however, for abandonment and disconnection costs associated with existing producing wells, salvage values, reclamation of existing or future well sites or the abandonment and reclamation of any facilities. Therefore, the abandonment and reclamation costs in the reserve report should not be interpreted as a comprehensive model of the abandonment and reclamation costs for the Corporation, which are estimated herein under the section entitled "*Additional Information Concerning Abandonment and Reclamation Costs*".

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000's)	Unit Value ($/Boe) of Net Reserves (Before Income Taxes and Discounted at 10%/year)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	96,178	25.41
	Natural Gas (including by-products but excluding solution gas from oil wells)	167,677	11.72
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	151,871	21.63
	Natural Gas (including by-products but excluding solution gas from oil wells)	244,125	10.70

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Sproule Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

3. Only well abandonment costs and disconnect costs related to proved undeveloped and proved plus probable reserves on future undrilled development locations have been included in this estimate. See the section entitled "*Additional Information Concerning Abandonment and Reclamation Costs*" for a comprehensive model of abandonment and reclamation costs.

Reserve Categories

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

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions.

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

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

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

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

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

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

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

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

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

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

Levels of Certainty for Reported Reserves

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

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

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

A quantitative measure of the probability associated with a reserves estimate is generated only when a probabilistic estimate is conducted. The majority of reserves estimates will be performed using deterministic methods that do not provide a quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook. Whether deterministic or probabilistic methods are used, evaluators are expressing their professional judgement as to what are reasonable estimates.

Forecast Prices and Costs

Forecast prices and costs are those:

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

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

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized in the Sproule Report were the average forecast prices published by Sproule, GLJ Petroleum Consultants Ltd., McDaniel & Associates Consultants Ltd. and AJM Petroleum Consultants Ltd. as at December 31, 2011, which were as follows**:**

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

Year	WTI Cushing Oklahoma ($US/Bbl)	Light Sweet Crude Oil at Edmonton 40° API ($Cdn/Bbl)	NATURAL GAS LIQUIDS Edmonton Butane ($Cdn/Bbl)	NATURAL GAS LIQUIDS Edmonton Pentanes ($Cdn/Bbl)	NATURAL GAS AECO -C Spot ($Cdn/ MMBtu)	INFLATION RATES(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast							
2012	98.14	97.96	77.03	105.06	3.41	2.00	0.99
2013	98.60	98.44	78.37	104.35	4.05	2.00	0.99
2014	99.01	98.85	78.76	103.48	4.53	2.00	0.99
2015	101.08	100.89	80.33	105.66	5.21	2.00	0.99
2016	102.33	102.12	81.34	106.95	5.56	2.00	0.99
2017	103.61	103.39	82.34	108.30	5.91	2.00	0.99
2018	105.23	104.99	83.62	110.01	6.19	2.00	0.99
2019	107.04	106.80	85.05	111.90	6.42	2.00	0.99
2020	108.89	108.63	86.51	113.85	6.68	2.00	0.99
2021	111.09	110.85	88.28	116.17	6.86	2.00	0.99
2022	113.30	113.05	90.04	118.48	6.99	2.00	0.99
2023	115.57	115.31	91.83	120.84	7.13	2.00	0.99
2024	117.87	117.62	93.67	123.26	7.27	2.00	0.99
2025	120.23	119.96	95.55	125.73	7.43	2.00	0.99
2026	122.66	122.38	97.46	128.26	7.58	2.00	0.99
2027	125.11	124.83	99.41	130.83	7.73	2.00	0.99
2028	127.62	127.33	101.40	133.45	7.88	2.00	0.99
2029	130.16	129.86	103.41	136.10	8.04	2.00	0.99
2030	132.76	131.21	102.24	138.83	8.77	2.00	0.99
2031	135.43	133.67	104.18	141.67	8.92	2.00	0.99
Thereafter	+ 2.0%	+ 2.0%	+ 2.0%	+ 2.0%	+ 2.0%	+ 2.0%	

Notes:

(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by Vero for the year ended December 31, 2011 were $3.96/Mcf for natural gas, $89.74/Bbl for light and medium gravity crude oil and $72.88/Bbl for NGLs.

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

The extent and character of all factual data supplied to Sproule was accepted by Sproule as represented. No field inspections were conducted.

After tax NPV of reserves are dependent on various factors including the following and disclosure should be considered:

- Forecast future capital expenditure required to achieve the forecast production;
- Interaction with, or deductibility of, government royalties or other proportionate sharing rights;
- Inclusion of existing tax pool balances of the issuer (inclusion is prescribed for issuer-aggregate estimates according to section 7 of Volume 1 of COGE Handbook);
- Tax pool write-off rates;

- Sequence in which tax pools are utilized;
- Applicability of special tax incentives; and
- Forecast production revenue and expenses.

Each of these can have a significant impact on the outcome, which could mislead investors if not properly considered in the evaluation or if the issuer's disclosure does not provide sufficient accompanying information to enable a reader to make an informed decision including the following:

- A general explanation of the method and assumptions used in the issuer's calculation, worded to reflect its specific circumstance and the approach taken. This need not be detailed, but major aspects should be addressed, such as whether tax pools have been included in the evaluation;
- An explanatory statement to the following effect:

The after-tax net present value of the Corporation's properties here reflects the tax burden on the properties on a stand-alone basis. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion and analysis of the Corporation should be consulted for information at the level of the business entity.

Reconciliation of Changes in Reserves

The following table sets out the reconciliation of Vero's gross reserves based on forecast prices and costs by principal product type:

	LIGHT AND MEDIUM OIL			**ASSOCIATED AND NON-ASSOCIATED GAS**			**NATURAL GAS LIQUIDS**		
FACTORS	**Gross Proved (Mbbls)**	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**	**Gross Proved (MMcf)**	**Gross Probable (MMcf)**	**Gross Proved Plus Probable (MMcf)**	**Gross Proved (Mbbls)**	**Gross Probable (Mbbls)**	**Gross Proved Plus Probable (Mbbls)**
December 31, 2010	2,444	1,849	4,292	88,373	55,313	143,685	2,879	1,822	4,701
Extensions	1,120	1,001	2,120	15,754	7,078	22,832	529	237	766
Improved Recovery	0	0	0	0	0	0	0	0	0
Technical Revisions	(472)	(412)	(884)	1,950	(5,564)	(3,614)	(120)	(263)	(383)
Discoveries	212	81	293	4,795	1,378	6,173	147	44	191
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	(3)	(5)	(8)	(1,965)	(1,301)	(3,266)	(64)	(42)	(106)
Economic Factors	(1)	(4)	(5)	(3,015)	(101)	(3,116)	(87)	1	(87)
Production	(392)	0	(392)	(15,313)	0	(15,313)	(417)	0	(417)
December 31, 2011	2,908	2,509	5,416	90,579	56,802	147,382	2,867	1,798	4,665

Notes:

(1) The Corporation has no unconventional reserves (bitumen, synthetic crude oil, natural gas from coal, etc.).
(2) There are no heavy oil reserves in 2011.
(3) Numbers may not add due to rounding.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to Vero's assets for the years ended December 31, 2011, 2010 and 2009, and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

	Light and Medium Oil (Gross Mbbl)		Natural Gas (Gross MMcf)		NGLs (Gross Mbbl)	
Year	**First Attributed**	**Remaining Booked**	**First Attributed**	**Remaining Booked**	**First Attributed**	**Remaining Booked**
Prior to Dec. 31, 2009(1)	91	91	31,374	31,374	927	927
Dec. 31, 2009	11	102	6,216	30,402	192	970
Dec. 31, 2010	1,060	1,152	8,853	31,551	336	1,131
Dec. 31, 2011	850	1,101	10,739	31,422	380	1,075

Probable Undeveloped Reserves

	Light and Medium Oil (Gross Mbbl)		Natural Gas (Gross MMcf)		NGLs (Gross Mbbl)	
Year	**First Attributed**	**Remaining Booked**	**First Attributed**	**Remaining Booked**	**First Attributed**	**Remaining Booked**
Prior to Dec. 31, 2009(1)	23	23	19,267	19,267	563	563
Dec. 31, 2009	191	214	2,889	19,033	96	628
Dec. 31, 2010	1,243	1,266	17,851	37,157	642	1,259
Dec. 31, 2011	892	1,593	5,892	36,231	201	1,172

Notes:

(1) First attributed and Remaining Booked numbers in the "Prior to" row equal the closing balance in the preceding year.

Proved and probable undeveloped reserves are attributed in accordance with standards and procedures contained in the COGE Handbook. In general, once proved and/or probable undeveloped reserves are identified they are scheduled into Vero's development plans. Normally, the Corporation plans to develop its proved and probable undeveloped reserves within two years. However, if the economic climate is not conducive to developing these reserves within two years, Vero may, in its discretion, defer the development into the future. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to commodity pricing, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies (such as water breakthrough, accelerated depletion));
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and

- surface access issues (landowners, weather conditions, regulatory approvals).

Significant Factors or Uncertainties

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

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

In 2011 the industry experienced continued reductions in natural gas prices which has created significant uncertainty regarding particular components of the reserves data. The reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are all beyond our control (see "*Risk Factors*").

Future Development Costs

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

Forecast Prices and Costs (Undiscounted) (000's)

Year	**Proved Reserves**	**Proved Plus Probable Reserves**
2012	55,723	85,125
2013	30,266	67,411
2014	29,664	37,869
2015	16,621	34,283
Thereafter	-	161
Total	132,274	224,849

We expect that the capital listed in the preceding table will be funded through internally generated cash flows and will not have any associated funding costs. Therefore, we do not expect that the costs of funding will affect the disclosed reserves of future net revenue. However, the availability of internal cash flows is dictated in a significant way by commodity prices. If commodity prices decline, projects may be delayed as the funds available become restricted.

Other Oil and Gas Information

Principal Properties

The following is a description of Vero's principal oil and natural gas properties as at December 31, 2011. Unless otherwise indicated, production stated is the average production for the year ended December 31, 2011 received by us in respect of our working interest share before deduction of royalties. Unless otherwise specified, gross and net acres and well count information is as at December 31, 2011.

The following descriptions are provided as at December 31, 2011 and include the Disposition Assets which are no longer owned by Vero following completion of the 2012 Gas Sale Transaction. For a description of Vero's principal properties following completion of the 2012 Gas Asset Sale Transaction, please see "*Reserves Data and Other Oil and Gas Information Following Completion of the 2012 Gas Asset Sale Transaction – Principal Properties*".

Vero's core area of operations is centered in an area approximately 150 kilometers west of the city of Edmonton and is situated between the towns of Whitecourt to the north and Rocky Mountain House to the south. The Company's properties are characterized by multi-zoned liquids rich natural gas and sweet light oil targets with depth ranges predominantly from 1,500 to 2,600 meters. Production for the year averaged 9,238 BOE/d (76% natural gas) with a year end exit rate of approximately 9,366 BOE/d (74% natural gas). At December 31, 2011 Vero's properties were comprised of 265 (122.3 net) producing natural gas wells and 76 (49.5 net) producing oil wells.

In 2011, Vero drilled 31 (23.6 net) wells, resulting in 10 (7.9 net) gas wells, and 20 (14.7 net) oil wells. Of the successful wells, 28 (21.3 net) are tied-in and producing and 1 (0.3 net) are in the process of completion and/or awaiting tie-in.

During the year the total land holdings were positively influenced by purchases at Alberta Crown land-sales. At the end of 2011 Vero's land holdings were 162,832 gross (100,293 net) developed acres and 111,997 (87,326 net) undeveloped acres.

Edson is the Corporation's largest and most active drilling and production area where a total of 31 gross (23.6 net) wells were drilled in 2011. Production for Edson averaged 8,066 BOE/d (75% natural gas) for the year. At the Corporation's inception just over five years ago the drilling program consisted primarily of vertical wells along with a small percentage of horizontal drills. Due to the continued success, the horizontal drilling portion of our program has steadily increased so that at year end a total of 92 gross (74.6 net) horizontal wells had been drilled in Edson since the beginning of Vero. In 2011 all wells drilled in Edson were horizontal. Industry activity in the light sweet oil bearing sands of the Cardium Formation was strong throughout 2011. Horizontal, multi-frac wells have extended the previously defined boundaries of the Cardium play. In late 2009 Vero turned its attention towards evaluating this play across its land base so that at year end 2011 a total of 37 (27.6 net) wells had been drilled. In 2011 alone Vero drilled 19 (13.9 net) Cardium wells with nineteen on production and one other completed and waiting to be brought on-production in the early days of 2012. The 2011 drilling program was very focused on the Cardium play with 61% of our horizontal wells targeting this light oil reservoir.

The Whitecourt area is located approximately 150 kilometers northwest of Edmonton and Vero's interest in the area as at 2011 year end consisted of 36 (20.4 net) total producing wells of which 34 (19.4 net) are natural gas wells and 2 (1 net) are oil wells. Whitecourt production averaged 866 BOE/d for the year ended December 31, 2011, weighted 89% to natural gas. The Whitecourt area was not a focus area for 2011 as Vero's efforts turned toward its Cardium land base in Edson. At year end Vero's acreage in the area consisted of 32,160 gross (18,923 net) developed acres and 18,080 gross (13,857 net) undeveloped acres.

Oil And Gas Wells

The following table sets forth the number and status of wells in which the Corporation had a working interest as at December 31, 2011.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	68	42.8	3	1.9	225	137.5	169	89.7
Saskatchewan	-	-	-	-	-	-	5	4.3
Total	68	42.8	3	1.9	225	137.5	174	94.0

Land Holdings Including Properties with no Attributed Reserves

The following table sets out the Corporation's developed and undeveloped land holdings as at December 31, 2011.

	Developed Acres		**Undeveloped Acres**		**Total Acres**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	162,023	99,484	109,399	84,728	271,422	184,212
Saskatchewan	809	809	-	-	809	809
British Columbia	-	-	2,598	2,598	2,598	2,598
Total	162,832	100,293	111,997	87,326	274,829	187,619

There are no material work commitments associated with the Corporation's undeveloped land holdings as of the date of this AIF. The Corporation's rights to explore, develop and/or exploit 20,218 net acres of its undeveloped land holdings may expire by December 31, 2012. We plan to drill or submit applications to continue selected portions of the above acreage, which we retained following completion of the 2012 Gas Asset Sale Transaction.

Forward Contracts and Marketing

Vero's crude oil, natural gas and natural gas liquid production is sold directly to credit-worthy counterparties, with the exception of small quantities of non-operated properties, which are marketed by the operator of the well.

The board of directors of Vero has authorized management to hedge up to 50% of its total production from time to time to provide downside commodity price protection through the use of financial derivative structures and short-term physical contracts. As at December 31, 2011 the following hedges were outstanding.

Contract	**Amount**	**Term**	**Price**	**Type**
Costless collar	250 bbl/d	Apr. 1,2012 - Mar. 31, 2013	\$90 - \$110	Financial
Costless collar	500 bbl/d	Jan. 1, 2011-Dec. 31, 2012	\$85 - \$109.25	Financial
Costless collar	500 bbl/d	Apr. 1, 2011-Mar. 31, 2012	\$85 - \$104	Financial

Additional Information Concerning Abandonment and Reclamation Costs

Well abandonment costs on future undeveloped reserve wells have been included in the economic forecasts contained in the Sproule Report, while abandonment costs on developed reserves wells, pipelines, production facilities and site reclamation have been excluded. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements.

As at December 31, 2011 the Corporation has 276.2 net wells for which it expects to incur abandonment and reclamation costs.

The Corporation prepares an annual, internal estimate of the Corporation's total future asset retirement obligation, based on net ownership interest in all wells and facilities, including wells with no reserves attributed including costs to abandon the wells, facilities and pipelines and reclaim the sites and the estimating timing of the costs to be incurred in future periods. Pursuant to this evaluation, the estimated undiscounted total value of the Corporation's future abandonment and reclamation costs is estimated to be \$23.4 million as at December 31, 2011. This amount is comprised of \$13.5 million with respect to existing wells and facilities as described in the Corporation's financial statements for the year ended December 31, 2011; \$6.8 million related to proved and probable undeveloped reserves as included in the Sproule Report; and \$3.1 million for reclamation costs on undeveloped wells related to the undeveloped wells that are shown in the Sproule Report. As at December 31, 2011, the undiscounted net salvage value of the Corporation's gas plants, compressors and facilities was estimated at \$5.1 million. The Sproule Report includes an undiscounted amount of \$6.8 million with respect to expected future well abandonment costs related specifically to proved and probable undeveloped reserves on undrilled development locations only and 100% of such amount is included in the values captioned "Proved and Probable" in the summary tables of Net Present Value of Future Revenue (See "*Disclosure of Reserves Data*").

The following table sets forth the estimated future asset retirement obligations and estimated net salvage values:

	Undiscounted ($000's)	**Discounted at 10% ($000's)**
Well abandonment costs for undeveloped reserves included in the Sproule Report	6,775	582
Other reclamation costs for undeveloped reserves not included in the Sproule Report	3,081	162
Abandonment and reclamation costs for developed reserves not included in the Sproule Report	13,523	4,188
Total estimated future abandonment and reclamation costs	23,379	4,932
Salvage value	(5,109)	(1,414)
Abandonment and reclamation costs, net of salvage	18,270	3,518
Well abandonment costs for undeveloped reserves included in the Sproule Report	(6,775)	(582)
Estimate of additional future abandonment and reclamation costs, net of salvage	11,495	2,936

The estimated total amount of abandonment and reclamation costs the Company expects to pay in the next three years is approximately $222 thousand.

Of the total future well abandonment costs included in the Sproule Report an undiscounted amount of $3.4 million ($0.4 million discounted at 10 percent) relates to expected future well abandonment and disconnection costs on proved undeveloped reserves on undrilled development locations only.

Tax Horizon

The income tax deducted in the calculation of future net revenue above assumes a blow-down scenario whereby Vero produces out its existing reserves and does not reinvest any capital. Under this scenario, and given Vero's existing tax pools at December 31, 2011, it is currently anticipated that Vero would not be taxable in 2012 or 2013.

Capital Expenditures

The following table summarizes capital expenditures (including capitalized and general administrative expenses) related to the Corporation's activities for the year ended December 31, 2011:

	000's
Property acquisition costs	
Proved properties	40
Undeveloped properties[(1)]	1,284
Exploration costs	34,821
Development costs	88,834
Administrative	69
Dispositions	(5,497)
Total	119,551

Notes:

(1) Cost of land acquired and non-producing lease rentals on those lands.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Vero participated in the year ended December 31, 2011.

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Natural Gas	3	2.4	8	6.5
Light and Medium Oil	5	3.7	14	10.4
Service	-	-	-	-
Stratographic Test	-	-	-	-
Dry	1	1.0	-	-
Total	9	7.1	22	16.9

See "*Principal Properties*" under "*Reserves Data and Other Oil and Gas Information Following Completion of the 2012 Gas Asset Sale Transaction*" for a description of the Corporation's most important current and likely exploration and development plans during 2011.

Production Estimates

The following table sets out the volume of the Corporation's production estimated for the year ended December 31, 2012 as evaluated by Sproule, which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*".

	Light and Medium Oil	**Natural Gas**	**Natural Gas Liquids**	**Total**
Reserves Category	**Gross (Bbls/d)**	**Gross (Mcf/d)**	**Gross (Bbls/d)**	**Gross (BOE/d)**
PROVED				
Edson	1,346	30,268	984	7,375
Other Properties	101	4,489	67	916
Total Proved	1,447	34,757	1,051	8,291
PROVED PLUS PROBABLE				
Edson	1,832	35,171	1,148	8,841
Other Properties	123	4,700	70	977
TOTAL PROVED PLUS PROBABLE	1,955	39,871	1,218	9,818

The Corporation's Edson field is the only field which accounts for 20% or more of the Corporation's estimated 2012 production in the Sproule Report.

Production History

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

	2011			
	Quarter Ended			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production[(1)]				
Light and Medium Crude Oil (Bbls/d)	1,089	1,339	960	1,051
Natural Gas (Mcf/d)	40,417	42,244	47,581	38,022
NGLs (Bbls/d)	1,094	883	1,382	1,101
Combined (BOE/d)	8,919	9,262	10,272	8,489
Average Price Received				
Light and Medium Crude Oil ($/Bbl)	91.86	86.60	97.90	84.23
Natural Gas ($/Mcf)	3.48	3.99	4.21	4.12
NGLs ($/Bbls)	75.48	63.91	78.01	71.18
Combined ($/BOE)	36.24	36.81	39.17	38.11
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	9.16	11.12	9.43	6.37
Natural Gas ($/Mcf)	0.21	0.25	0.25	0.11
NGLs ($/Bbls)	19.57	22.59	18.58	18.34
Combined ($/BOE)	4.26	5.45	4.27	3.37
Operating & Transportation Expenses ($/BOE)				
Light and Medium Crude Oil ($/Bbls)	8.75	26.46	8.33	7.20
Natural Gas ($/Mcf)	1.48	0.75	1.58	1.61
NGLs ($/Bbls)	15.28	16.88	14.90	14.43
Combined ($/BOE)	9.79	9.93	9.56	9.43
Netback Received ($/BOE)[(2)]				
Light and Medium Crude Oil ($/Bbls)	71.19	49.02	80.14	70.66
Natural Gas ($/Mcf)	2.42	2.99	2.38	2.40
NGLs ($/Bbls)	37.22	24.44	44.53	38.41
Combined ($/BOE)	23.57	21.43	25.34	25.32

Notes:

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

The following table indicates the Corporation's average daily production from its important fields for the year ended December 31, 2011:

	Light and Medium Crude Oil (Bbls/d)	Natural Gas (Mcf/d)	NGLS (Bbls/d)	BOE (BOE/d)
Edson	1,003	36,211	1,028	8,066
Whitecourt	34	4,625	61	866
Other Alberta	74	1,237	26	304
Total Alberta	1,109	42,073	1,115	9,236
Saskatchewan	2	-	-	2
Total Company	1,111	42,073	1,115	9,238

Vero's crude oil production for the year ended December 31, 2011 was 100% light and medium quality crude oil (25° API or greater).

For the year ended December 31, 2011, approximately 48% of Vero's gross revenue was derived from natural gas production; 29% was derived from crude oil production; and 23% was derived from natural gas liquids.

RESERVES DATA AND OTHER OIL AND GAS INFORMATION FOLLOWING COMPLETION OF THE 2012 GAS ASSET SALE TRANSACTION

All information contained in this section of the AIF is related solely to the Corporation's Remaining Assets following completion of the 2012 Gas Asset Sale Transaction and is being provided in order to address the material changes which have occurred to Vero's Reserves Data and other oil and gas information contained elsewhere in this AIF following the year ended December 31, 2011.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon evaluation by Sproule with an effective date of December 31, 2011 contained in the Sproule Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves associated with the Remaining Assets and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information.

The forecast pricing used in the tables contained herein is based on the average forecast prices published by Sproule, GLJ Petroleum Consultants Ltd., McDaniel & Associates Consultants Ltd. and AJM Petroleum Consultants Ltd. as at December 31, which pricing details are more specifically set forth in this AIF under "*Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data*".

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

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE FOR REMAINING ASSETS
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS

	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserves Category	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbls)**	**Net (Mbbls)**
Proved						
Developed Producing	1,476.2	1,268.5	6,216	5,584	209.8	139.2
Developed Non-Producing	104.3	93.2	302	283	9.6	6.9
Undeveloped	1,099.9	956.4	2,778	2,533	95.9	71.1
Total Proved	**2,680.4**	**2,318.1**	**9,296**	**8,400**	**315.3**	**217.1**
Probable	2,343.8	1,897.5	10,580	9,472	366.9	239.9
Total Proved Plus Probable	**5,024.2**	**4,215.6**	**19,876**	**17,872**	**682.2**	**457.1**

	Before Income Taxes Discounted At (%/year)					Unit Value Before Income Tax Discounted at 10%/Year(1)
Reserves Category	**0**	**5**	**10**	**15**	**20**	**($/Boe)**
Proved						
Developed Producing	112,967	88,654	74,139	64,551	57,740	31.71
Developed Non-Producing	8,180	6,637	5,656	4,982	4,490	38.41
Undeveloped	41,517	25,825	16,005	9,438	4,806	11.04
Total Proved	**162,664**	**121,116**	**95,800**	**78,971**	**67,036**	**24.34**
Probable	168,382	90,306	55,965	37,818	26,916	15.06
Total Proved Plus Probable	**331,046**	**211,422**	**151,765**	**116,788**	**93,952**	**19.84**

Notes:

1. Unit value before income tax is calculated based on net reserve volumes.

2. Only well abandonment costs and disconnect costs related to proved undeveloped and proved plus probable reserves on future undrilled development locations have been included in this estimate. See the section entitled "*Additional Information Concerning Abandonment and Reclamation Costs*" for a comprehensive model of abandonment and reclamation costs.

The below table includes after-tax values that were derived internally by Vero and based upon estimates of corporate tax pools that would be in existence after the 2012 Gas Asset Sale Transaction.

	After Income Taxes Discounted At (%/year) (2)				
Reserves Category	**0**	**5**	**10**	**15**	**20**
Proved					
Developed Producing	112,967	88,654	74,139	64,551	57,740
Developed Non-Producing	7,422	6,405	5,580	4,956	4,480
Undeveloped	31,138	20,193	12,786	7,516	3,614
Total Proved	**151,526**	**115,252**	**92,505**	**77,022**	**65,835**
Probable	126,294	67,594	41,746	28,056	19,803
Total Proved Plus Probable	**277,820**	**182,846**	**134,251**	**105,078**	**85,637**

Notes:

1. Only well abandonment costs and disconnect costs related to proved and proved plus probable undeveloped reserves on future undrilled development locations have been included in this estimate. See section entitled "*Additional Information Concerning Abandonment and Reclamation Costs*" for a comprehensive model of abandonment and reclamation costs.

2. After income tax net present values were estimated by Vero Energy Inc.

TOTAL FUTURE NET REVENUE FOR REMAINING ASSETS (UNDISCOUNTED) AS OF DECEMBER 31, 2011 FORECAST PRICES AND COSTS ($000'S)

Reserves Category	**Revenue**	**Royalties**	**Operating Costs**	**Development Costs**	**Abandonment Costs**(1)	**Future Net Revenue Before Income Taxes**	**Income Taxes**(2)	**Future Net Revenue After Future Income Taxes**(2)
Proved	350,713	49,586	90,669	46,556	1,238	162,664	11,138	151,526
Proved Plus Probable	736,736	119,450	195,721	87,702	2,818	331,046	53,226	277,820

Notes to Future Net Revenue Data Tables:

1. Only well abandonment costs and disconnect costs related to proved and proved plus probable undeveloped reserves on future undrilled development locations have been included in this estimate. No allowance was made, however, for abandonment and disconnection costs associated with existing producing wells, salvage values, reclamation of existing or future well sites or the abandonment and reclamation of any facilities. Therefore, the abandonment and reclamation costs in the reserve report should not be interpreted as a comprehensive model of the abandonment and reclamation costs for the Corporation, which are estimated herein under the section entitled "*Additional Information Concerning Abandonment and Reclamation Costs*").

2. Future income taxes and after tax future net revenue were estimated by Vero Energy Inc.

FUTURE NET REVENUE FOR REMAINING ASSETS
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000's)	Unit Value ($/Boe) of Net Reserves (Before Income Taxes and Discounted at 10%/year)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	89,128	25.65
	Natural Gas (including by-products but excluding solution gas from oil wells)	6,671	14.48
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	141,231	21.79
	Natural Gas (including by-products but excluding solution gas from oil wells)	10,534	9.01

Significant Factors or Uncertainties

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

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

In 2011 the industry experienced continued reductions in natural gas prices which has created significant uncertainty regarding particular components of the reserves data. The reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are all beyond our control (see "*Risk Factors*").

Future Development Costs

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

Forecast Prices and Costs (Undiscounted) (000's)

Year	Proved Reserves	Proved Plus Probable Reserves
2012	36,073	62,111
2013	10,483	18,631
2014	-	-
2015	-	6,960
2016	-	-
Thereafter	-	-
Total	46,556	87,702

We expect that the capital listed in the preceding table will be funded through internally generated cash flows and will not have any associated funding costs. Therefore, we do not expect that the costs of funding will affect the disclosed reserves of future net revenue. However, the availability of internal cash flows is dictated in a significant way by commodity prices. If commodity prices decline, projects may be delayed as the funds available become restricted.

Other Oil and Gas Information

Principal Properties

The following is a description of Vero's principal oil and natural gas properties comprising the Remaining Assets as at December 31, 2011. Unless otherwise indicated, production stated is the average production for the year ended December 31, 2011 received by us in respect of our working interest share before deduction of royalties. Unless otherwise specified, gross and net acres and well count information is as at December 31, 2011.

The Remaining Assets are predominantly located in the Edson area and are represented by high working interest, operated, light oil production. As at December 31, 2011 production was approximately 1,800 boe/d (67% oil and natural gas liquids). There are 77,652 net developed acres and 64,424 net undeveloped acres. Vero has an initial capital budget of $62.5 million and plans to drill 28-30 (16-17 net) Cardium horizontal wells during 2012. The operating netbacks on the Retained Assets are approximately $50/boe.

Oil And Gas Wells

The following table sets forth the number and status of wells comprising the Remaining Assets in which the Corporation had a working interest as at December 31, 2011.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	52	36.1	5	3.3	8	5.3	33	21.1
Saskatchewan	-	-	1	0.3	-	-	3	3.0
Total	52	36.1	6	3.6	8	5.3	36	24.1

Land Holdings Including Properties with no Attributed Reserves

The following table sets out the Corporation's developed and undeveloped land holdings comprising the Remaining Assets as at December 31, 2011.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	18,462	12,419	98,776	61,826	117,238	74,245
Saskatchewan	809	809	-	-	809	809
British Columbia	-	-	2,598	2,598	2,598	2,598
Total	19,271	13,228	101,374	64,424	120,645	77,652

There are no material work commitments associated with the Corporation's undeveloped land holdings comprising the Remaining Assets as of the date of this AIF. The Corporation's rights to explore, develop and/or exploit 8,200 net acres of these undeveloped land holdings may expire by December 31, 2012. We plan to drill or submit applications to continue selected portions of the above acreage.

Forward Contracts and Marketing

Vero's crude oil, natural gas and natural gas liquid production is sold directly to credit-worthy counterparties, with the exception of small quantities of non-operated properties, which are marketed by the operator of the well.

The board of directors of Vero has authorized management to hedge up to 50% of its total production from time to time to provide downside commodity price protection through the use of financial derivative structures and short-term physical contracts. As at December 31, 2011 the following hedges were outstanding in respect of the Remaining Assets.

Contract	Amount	Term	Price	Type
Costless collar	250 bbl/d	Apr. 1,2012 - Mar. 31, 2013	$90 - $110	Financial
Costless collar	500 bbl/d	Jan. 1, 2011-Dec. 31, 2012	$85 - $109.25	Financial
Costless collar	500 bbl/d	Apr. 1, 2011-Mar. 31, 2012	$85 - $104	Financial

Additional Information Concerning Abandonment and Reclamation Costs

Well abandonment costs on future undeveloped reserve wells have been included in the economic forecasts contained in the Sproule Report, while abandonment costs on developed reserves wells, pipelines, production facilities and site reclamation have been excluded. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements.

As at December 31, 2011 the Corporation has 69.1 net wells for which it expects to incur abandonment and reclamation costs.

The Corporation prepares an annual, internal estimate of the Corporation's total future asset retirement obligation, based on net ownership interest in all wells and facilities, including wells with no reserves attributed including costs to abandon the wells, facilities and pipelines and reclaim the sites and the estimating timing of the costs to be incurred in future periods. Pursuant to this evaluation, the estimated undiscounted total value of the Corporation's future abandonment and reclamation costs is estimated to be $7.2 million as at December 31, 2011. This amount is comprised of $3.3 million with respect to existing wells and facilities as described in the Corporation's financial statements for the year ended December 31, 2011; $2.8 million related to proved and probable undeveloped reserves as included in the Sproule Report; and $1.0 million for reclamation costs on undeveloped wells related to the undeveloped wells that are shown in the Sproule Report. As at December 31, 2011, the undiscounted net salvage value of the Corporation's gas plants, compressors and facilities was estimated at $3.0 million. The Sproule Report includes an undiscounted amount of $2.8 million with respect to expected future well abandonment costs related specifically to proved and probable undeveloped reserves on undrilled development locations only and 100% of such amount is included in the values captioned "Proved and Probable" in the summary tables of Net Present Value of Future Revenue (See "*Disclosure of Reserves Data*").

The following table sets forth the estimated future asset retirement obligations and estimated net salvage values:

	Undiscounted ($000's)	Discounted at 10% ($000's)
Well abandonment costs for undeveloped reserves included in the Sproule Report	2,818	213
Other reclamation costs for undeveloped reserves not included in the Sproule Report	1,025	19
Abandonment and reclamation costs for developed reserves not included in the Sproule Report	3,317	905
Total estimated future abandonment and reclamation costs	7,160	1,137
Salvage value	(2,974)	(811)
Abandonment and reclamation costs, net of salvage	4,186	326
Well abandonment costs for undeveloped reserves included in the Sproule Report	(2,818)	(213)
Estimate of additional future abandonment and reclamation costs, net of salvage	1,368	113

The estimated total amount of abandonment and reclamation costs the Company expects to pay in the next three years is approximately $70 thousand.

Of the abandonment and disconnection costs included in the Sproule Report, the Retained assets include an undiscounted amount of $1.2 million ($0.2 million discounted at 10 percent) which relate to expected future abandonment and disconnection costs on proved undeveloped reserves on undrilled development locations only.

Capital Expenditures

The following table summarizes capital expenditures related to the Corporation's activities associated with the Remaining Assets for the year ended December 31, 2011:

	000's
Property acquisition costs	
Proved properties	-
Undeveloped properties(1)	-
Exploration costs	12,681
Development costs	47,041
Total	59,722

Notes:

(1) Cost of land acquired and non-producing lease rentals on those lands.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells on the Remaining Assets in which Vero participated in the year ended December 31, 2011.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Natural Gas	-	-	-	-
Light and Medium Oil	4	2.5	15	11.4
Service	-	-	-	-
Dry	-	-	-	-
Total	4	2.5	15	11.4

Production Estimates

The following table sets out the volume of the Corporation's production attributed to the Remaining Assets estimated for the year ended December 31, 2012 as evaluated by Sproule, which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables above.

	Light and Medium Oil	Natural Gas	Natural Gas Liquids	Total
Reserves Category	**Gross (Bbls/d)**	**Gross (Mcf/d)**	**Gross (Bbls/d)**	**Gross (BOE/d)**
PROVED				
Edson	1,328	4,434	153	2,220
Total Proved	1,328	4,434	153	2,220
PROVED PLUS PROBABLE				
Edson	1,811	6,106	216	3,045
TOTAL PROVED PLUS PROBABLE	1,811	6,106	216	3,045

The Corporation's Edson field is the only field which accounts for 20% or more of the Corporation's estimated 2012 production attributed to the Remaining Assets in the Sproule Report.

Production History

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

	2011 Quarter Ended			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production[1]				
Light and Medium Crude Oil (Bbls/d)	947	939	858	877
Natural Gas (Mcf/d)	3,509	3,434	2,660	2,729
NGLs (Bbls/d)	129	124	88	83
Combined (BOE/d)	1,660	1,635	1,389	1,415
Average Price Received				
Light and Medium Crude Oil ($/Bbl)	92.12	87.60	98.25	84.91
Natural Gas ($/Mcf)	3.38	3.89	4.15	4.10
NGLs ($/Bbls)	68.21	65.39	75.49	70.29
Combined ($/BOE)	64.97	63.62	73.28	64.54
Royalties Paid				
Light and Medium Crude Oil ($/Bbls)	9.64	8.66	11.14	9.02
Natural Gas ($/Mcf)	0.54	0.62	0.78	0.59
NGLs ($/Bbls)	13.53	13.29	17.40	13.37
Combined ($/BOE)	6.75	6.39	8.47	6.77
Operating & Transportation Expenses ($/BOE)				
Light and Medium Crude Oil ($/Bbls)	8.45	8.68	8.43	7.85
Natural Gas ($/Mcf)	1.42	1.54	1.61	1.68
NGLs ($/Bbls)	15.78	16.44	15.10	14.73
Combined ($/BOE)	9.03	8.69	10.14	9.04

	2011			
	Quarter Ended			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Netback Received ($/BOE)(2)				
Light and Medium Crude Oil ($/Bbls)	74.03	70.26	78.68	68.04
Natural Gas ($/Mcf)	1.42	1.73	1.76	1.83
NGLs ($/Bbls)	38.90	35.66	42.99	42.19
Combined ($/BOE)	49.19	48.54	54.67	48.73

Notes:

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

The following table indicates the Corporation's average daily production from its important fields associated with the Remaining Assets for the year ended December 31, 2011:

	Light and Medium Crude Oil (Bbls/d)	**Natural Gas (Mcf/d)**	**NGLS (Bbls/d)**	**BOE (BOE/d)**
Edson	903	3,085	106	1,523
Total Alberta	903	3,085	106	1,523
Saskatchewan	2	-	-	2
Total Company	905	3,085	106	1,525

DIVIDENDS

Vero has not paid any dividends on the outstanding Common Shares. The board of directors of Vero will determine the actual timing, payment and amount of dividends, if any, that may be paid by Vero from time to time based upon, among other things, the cash flow, results of operations and financial conditions of Vero, the needs for funds to finance ongoing operations and other business considerations as the board of directors of Vero considers relevant. Payment of dividends is subject to the consent of Vero's lenders.

DESCRIPTION OF CAPITAL STRUCTURE

The authorized capital of Vero consists of an unlimited number of Common Shares and an unlimited number of first preferred shares issuable in series. The following is a summary of the rights, privileges, restrictions and conditions attaching to the securities of Vero.

Common Shares

Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Vero, to receive dividends if, as and when declared by the board of directors of Vero and to receive pro rata the remaining property and assets of Vero upon its dissolution, liquidation or winding-up, subject to the rights of shares having priority over the Common Shares. As at December 31, 2011 there were 48,992,479 Common Shares outstanding.

First Preferred Shares

Each series of first preferred shares shall consist of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the board of directors of Vero prior to the issuance thereof. With respect to the payment of dividends and distribution of assets in the event of liquidation, dissolution or winding-up of Vero, whether voluntary or involuntary, the first preferred shares are entitled to preference over the

Common Shares and any other shares ranking junior to the preferred shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the first preferred shares as may be determined at the time of creation of such series. As at December 31, 2011, no series of preferred shares has been created.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX and trade under the symbol "VRO". The following sets forth the price range and trading volume of the Common Shares on the TSX (as reported by the TSX) for the periods indicated:

	Price Range		
	High ($/share)	**Low ($/share)**	**Volume (000s)**
2011			
January	6.26	5.47	11,013
February	6.71	6.05	5,939
March	6.35	5.20	9,181
April	6.33	5.45	11,178
May	6.23	5.60	4,483
June	5.90	5.03	3,462
July	5.76	5.06	4,038
August	5.48	3.76	4,265
September	4.15	2.39	4,492
October	3.35	2.08	6,056
November	3.10	2.15	7,753
December	2.30	1.66	4,539
2012			
January	2.92	2.53	21,478
February	3.48	2.80	15,884
March (1-29)	2.72	2.53	5,401

ESCROWED SECURITIES

There are currently no securities of Vero held in escrow.

DIRECTORS AND OFFICERS

The names, province and country of residence, office held with the Corporation and principal occupation of the directors and officers of the Corporation as at the date hereof are set out below:

Name, Province and Country of Residence	Office Held	Principal Occupation Held During Last Five Years
Paul R. Baay (2)(3) Alberta, Canada	Chairman of the Board and a Director	Chairman and Chief Executive Officer of Touchstone Exploration Inc.; and Chairman of Veraz Petroleum Ltd.; prior thereto, President and Chief Executive Officer of True Energy Inc. since its formation on August 31, 2000 until May 14, 2007.
Douglas J. Bartole Alberta, Canada	President, Chief Executive Officer and a Director	President and Chief Executive Officer of Vero since November, 2005; prior thereto, Vice-President, Operations of True Energy Inc. since April 2005; prior thereto held various positions with True Energy Inc. since May 2001; prior thereto, from 1997-2000 held various positions with Renaissance Energy Ltd.

Name, Province and Country of Residence	Office Held	Principal Occupation Held During Last Five Years
Gerald N. Gilewicz Alberta, Canada	Vice-President, Finance and Chief Financial Officer	Vice-President of Finance and Chief Financial Officer of Vero since November, 2005; prior thereto, Vice President of Finance and Chief Financial Officer of Dual/Devlan Exploration Inc. from 1999 to November 2005; prior thereto, Senior Manager with Deloitte & Touche LLP.
Kevin W. Yakiwchuk Alberta, Canada	Vice-President, Exploration	Vice-President, Exploration of Vero since November, 2005; prior thereto, Vice-President, Exploration of True Energy Inc. since January 2005; prior thereto held various positions with True Energy Inc. since May 2001; prior thereto, geologist with Crestar Energy Inc. from April 2000-May 2001
Robert S. Bachynski Alberta, Canada	Vice President, Land	Vice President, Land of Vero since November 2005; prior thereto, Manager of Land at Apache Canada Ltd. since January 2001; prior thereto Manager Land at Canadian Forest Oil Ltd.; prior thereto has held management positions for various oil and gas exploration companies in Western Canada.
Shane Manchester Alberta, Canada	Vice-President, Operations	Vice President of Operations of Vero since April of 2006; prior thereto, Production and Engineering Manager with True Energy Inc.; prior thereto held various positions with Renaissance Energy Ltd., Husky Energy Ltd. and National Fuel Exploration Corporation.
Robert G. Rowley (2)(3)(4) Alberta, Canada	Director	Independent Businessman; Director and Officer of various private oil and gas companies; former Director of True Energy Inc.; former partner with Macleod Dixon LLP (Barristers and Solicitors).
Kenneth P. Acheson (1)(4) Alberta, Canada	Director	President, Kennington Properties Ltd. (commercial real estate company)
Clinton T. Broughton (1)(2)(4) Alberta, Canada	Director	Independent businessman; previously Chief Operating Officer then Executive Vice-President of True Energy Inc. from April 25, 2005 to November 30, 2006; prior thereto Vice President of True Energy Inc. since its formation on August 31, 2000
Paul C. Allard (1)(3) Alberta, Canada	Director	Project manager for DIA Holdings Ltd., a privately held real estate company that owns and develops commercial and residential real estate, since 2001.
Michael D. Sandrelli Alberta, Canada	Corporate Secretary	Partner with Burnet, Duckworth & Palmer LLP (Barristers and Solicitors).

Notes:

(1) Member of the Audit Committee.
(2) Member of the Reserves Committee.
(3) Member of the Compensation Committee.
(4) Member of the Corporate Governance Committee.
(5) Vero does not have an executive committee of its board of directors.

All of the directors and officers of Vero have been engaged for more than five years in their present principal occupations or executive positions with the same companies except as described above.

All of the directors of Vero were appointed in September 2005 except Mr. Allard who was appointed March 29, 2010. The term of office of each director expires at the next annual meeting of shareholders of the Corporation.

As at December 31, 2011, the directors and officers of Vero, as a group, beneficially owned, or controlled or directed, directly or indirectly, an aggregate of 3,523,835 Common Shares or approximately 7% of the issued and outstanding Common Shares.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of Vero will be subject to in connection with the operations of Vero. In particular, certain of the directors and officers of Vero are involved in managerial or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of Vero or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Vero. 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 Vero are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of References

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

Composition of the Audit Committee

The following table sets forth the names of each current member of the Audit Committee, whether such member is independent (in accordance with National Instrument 52-110), whether such member is financially literate and the relevant education and experience of such member:

Name	Independent	Financially Literate	Relevant Education and Experience
Kenneth P. Acheson (Chairman)	Yes	Yes	Mr. Acheson graduated from University of Manitoba with a Bachelor of Science and subsequently received his Chartered Accountant designation in 1982. Mr. Acheson chairs the audit committee of Vero Energy and is a member of the board of directors. Mr. Acheson served as chairman of the audit committee and on the board of directors of True Energy during 2005. Mr. Acheson is the president of a private real estate company.
Paul C. Allard	Yes	Yes	Mr. Allard holds a Bachelor of Arts degree and an M.B.A. from the University of Alberta in Edmonton. Mr. Allard is an independent businessman based out of Edmonton, Alberta. Since 2001 has been a principal with DIA Holdings Ltd., a privately held real estate company that owns and develops commercial and residential real estate in North America. Mr. Allard was appointed Director of Vero on March 29, 2010.

Clinton T. Broughton	Yes	Yes	Mr. Broughton is a professional engineer who has been active in the oil and gas industry for over 40 years including 22 in senior corporate management roles for both large and mid-sized companies. He retired as Executive Vice President and member of the Disclosures Committee of True Energy Trust on November 30, 2006.

Pre-Approval of Policies and Procedures

As of the date hereof the Audit Committee has not adopted specific policies or procedures in respect of the provision of non-audit services to the Corporation.

Vero has adopted the following policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by its auditors: the Audit Committee approves a schedule which summarizes the services to be provided that the Audit Committee believes to be typical, recurring or otherwise likely to be provided by its auditors. The schedule generally covers the period between the adoption of the schedule and the end of the year, but at the option of the Audit Committee, may cover a shorter or longer period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that: (i) the Audit Committee knows precisely what services it is being asked to pre-approve, and (ii) it is not necessary for any member of the Corporation's management to make judgment as to whether a proposed service fits within the preapproved services. Services that arise that were not contemplated in the schedule must be pre-approved by the Audit Committee, Chairman or a delegate of the Audit Committee. The full Audit Committee is informed of the services at its next meeting.

Vero has not approved any non-audit services on the basis of the *de minimis* exemptions. All non-audit services are pre-approved by the Audit Committee in accordance with the pre-approval policy referenced herein.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditor in each of the last two fiscal years for audit services were $88,200 in respect of the 2010 audit and $101,000 in respect of the 2011 audit. Audit fees consist of fees for the audit of our annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

Audit – Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance and related services by the Corporation's external auditor that are reasonably related to the performance of the audit or review of the Corporation's financial statements that are not reported under "Audit Fees" above were $37,800 in respect of 2010 and $40,500 in respect of 2011. These fees were for the review of the quarterly financial statements and MD&A of Vero. Also, $33,600 was billed in 2010 and $27,750 in 2011 in respect of review work done for the IFRS conversion opening balance sheet and the 2010 quarterly IFRS restatements.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Corporation's external auditor for tax compliance, tax advice, tax subscriptions and tax planning were $700 in 2010 and $800 in 2011. The fees noted were paid solely in relation to a tax subscription service provided by the auditors.

All Other Fees

The aggregate fees billed in each of the last two fiscal years for products and services provided by the Corporation's auditors other than services reported above were $18,400 in 2010 and nil in 2011. The fees in 2010 were related to a prospectus equity issuance in November.

HUMAN RESOURCES

Vero currently employs 27 full-time employees, 1 part-time employees and 4 consultants all of which are located in the head office.

INDUSTRY CONDITIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta and British Columbia, all of which should be carefully considered by investors in the oil and natural gas industry. It is not expected that any of these controls or regulations will affect the operations of Vero in a manner materially different than they would affect other oil and natural gas issuers of similar size. All current legislation is a matter of public record and Vero is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and natural gas industry.

Pricing and Marketing – Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

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

Pipeline Capacity

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

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 of energy resources to the U.S. or Mexico will be allowed, provided that any export restrictions are justified under certain provisions of the General Agreement on Tariffs and Trade, and further provided that any 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 or in such other representative period as the parties may agree), (ii) impose an export price higher than the domestic price subject to an exception with respect to certain measures which only restrict the volume of exports, and (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import price requirements, such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

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

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas, natural gas liquids and sulphur production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is also subject to certain provincial taxes and royalties. Operations not on Crown lands and subject to the provisions of specific agreements are also usually subject to royalties negotiated between the mineral owner and the lessee. These royalties are not eligible for incentive programs sponsored by various governments as discussed below. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the 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.

From time to time the governments of the western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and natural gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

Alberta

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010.

Royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $\$535/m^3$ compared to the previous royalty curve.

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

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

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

The Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

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

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

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. One aspect of the program was a drilling royalty credit program which provided up to a $200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. Another aspect of the program was a new well royalty program which provided for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated "volume cap" was reached. The *New Well Royalty Regulation*, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011.

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

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

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

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

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

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

Environmental Regulation

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

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

The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The

ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 29, 2011 the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the "**Revised LARP**") updating its prior draft of April 5, 2011 (the "**Draft LARP**"). The Revised LARP, while establishing several conservation areas of the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas. However, references to the cancellation of existing tenures have been removed from the Revised LARP and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

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

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets:

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

(b) 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.

(c) Under the Updated Action Plan, regulated entities were 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. However, with the recent withdrawal from the Kyoto Protocol, the future use of this mechanism may not occur.

(d) 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.

From December 7 to 18, 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets. In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any; the proposals contained in the Updated Action Plan will be implemented.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it will issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

Alberta

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

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

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

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

Land Tenure

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

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

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences that were granted prior to January 1, 2009 but continued after that date are not 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. The order in which these agreements will receive reversion notices will depend on their vintage and location, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and will revisit the decision in spring 2012.

RISK FACTORS

An investment in Common Shares would be subject to certain risks. Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation therein. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

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

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including fire, explosion, blowouts, cratering, sour gas releases, spills or other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In accordance with industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, the nature of certain risks is such that liabilities could exceed policy limits or not be covered, in either event the Corporation could incur significant costs.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels have caused significant volatility in commodity prices. These conditions have caused a decrease in confidence in the global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Prices, Markets and Marketing

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

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions, in the United States, Canada and Europe, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

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

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility. This volatility is often based on factors both related and unrelated to the financial performance or prospects of the issuers involved. The market price of the common shares of the Corporation could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Factors that could affect the market price of the common shares of the Corporation that are unrelated to the Corporation's performance include domestic and global commodity prices and market perceptions of the attractiveness of particular industries. The price at which the common shares of the Corporation will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. As a result, the Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Corporation's financial performance. The Corporation's return on assets operated by others therefore depends upon a number of factors that may be outside of the Corporation's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or the Corporation's ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

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

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering, processing and pipeline systems some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in the Corporation’s inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation’s production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities could harm the Corporation's business and, in turn, the Corporation’s financial condition, results of operations and cash flows.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could materially adversely affect the Corporation's ability to process its production and to deliver the same for sale.

Competition

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

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to exploration and production activities, 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 crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. The use of hydraulic fracturing is being used to produce commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs or third party or governmental claims, and could increase the Corporation's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

Environmental

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

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with greenhouse gas emissions legislation in Alberta or that may be enacted in other provinces. The Corporation may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which regulations are expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits regulated by the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition. See "Industry Conditions – Climate Change Regulation".

Variations in Foreign Exchange Rates and Interest Rates

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

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

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, which could negatively impact the market price of the common shares of the Corporation.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors, the overall state of the capital markets, the Corporation’s credit rating (if applicable), interest rates, tax burden due to new tax laws and investor appetite for investments in the energy industry and the Corporation's securities in particular. Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. As a result of the global economic volatility, the Corporation, along with many other oil and natural gas entities, may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited 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. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

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

The Corporation's borrowing base is determined and re-determined by the Corporation's lenders based on the Corporation's reserves, commodity prices, applicable discount rate and other factors as determined by the Corporation's lenders. A material decline in commodity prices could reduce the Corporation's borrowing base, therefore reducing the funds available to the Corporation under the credit facility which could result in a portion, or all, of the Corporation's bank indebtedness be required to be repaid.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time, could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

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

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

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

Availability of Drilling Equipment and Access

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

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title, or proposed legislative changes which affect title, to the oil and natural gas properties the Corporation controls that, if successful or made into law, could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Reserve Estimates

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

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

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

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

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, North Africa and other areas of the world have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Corporation's net production revenue.

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

Dilution

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

Management of Growth

The Corporation may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licenses and leases and working interests in licenses and leases. If the Corporation or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of the Corporation's licenses or leases or the working interests relating to a license or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations as the board of directors of the Corporation considers relevant.

Aboriginal Claims

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

Seasonality

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

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner.

Conflicts of Interest

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

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are PricewaterhouseCoopers LLP, Chartered Accountants, Petro-Canada Centre, Suite 3100, 111 5th Avenue SW, Calgary, Alberta T2P 5L3.

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Other than described below, Vero is not a party to any legal proceeding nor was it a party to, nor is or was any of its property the subject of any legal proceeding, during the financial year ended December 31, 2011, nor is Vero aware of any such contemplated legal proceedings, which involve a claim for damages, exclusive of interest and costs, that may exceed 10% of the current assets of Vero. See "*Risk Factors – Aboriginal Claims*".

Vero is named as a co-defendant in a lawsuit in relation to certain lands in the Edson area that were farmed out to Vero by a private oil and gas company. The farm out agreement entitled Vero to earn interests in these lands by drilling a well on these lands, which it did in late 2009. Another private oil and gas company (the “Plaintiff”) alleges that it already had a farm out agreement that encompassed these lands. The Plaintiff is seeking a declaration that its farm out agreement with the private company is valid and that Vero and the private company hold all revenues and expenses associated with these lands in trust for their benefit and is seeking a corresponding judgment for all amounts owing to it and further seeks an injunction restraining Vero from conducting any operations on these lands. Alternatively, the Plaintiff seeks judgment for damages in such amount to be proven at trial but estimated to be not less than $28 million and punitive damages of $500 thousand. While the claim appears to be principally directed at the private company, it involves Vero. Vero believes this claim to be without merit, is vigorously defending the action and has filed a counterclaim against the Plaintiff. The lawsuit was filed in the Court of Queen’s Bench of Alberta, judicial district of Calgary on July 8, 2009. Examinations for discovery are currently ongoing.

During the year ended December 31, 2011, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of the Corporation, any shareholder who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding

Common Shares, or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years of the Corporation or during the current financial year which has materially affected, or is reasonably expected to materially affect, the Corporation.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, there have been no material contracts entered into by the Corporation within the most recently completed financial year, or before the most recently completed financial year that are still in effect other than the Gas Asset Sale Agreement.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument NI 51-102 by Vero during, or related to, the year ended December 31, 2011 other than Sproule, Vero's independent engineering evaluators, and PricewaterhouseCoopers LLP, Vero’s auditors. None of the principals of Sproule had any registered or beneficial interests, direct or indirect, in any securities or other property of Vero or of Vero's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. PricewaterhouseCoopers LLP, Vero’s auditor’s, are independent in accordance with the auditor’s rules of professional conduct in Canada.

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

ADDITIONAL INFORMATION

Additional information relating to the Corporation can 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 will be contained in the Corporation's information circular and proxy statement for the Corporation's annual meeting of shareholders to be held on June 18, 2012. Additional financial information is contained in the Corporation's consolidated financial statements and the related management's discussion and analysis for the year ended December 31, 2011.

Additional copies of this Annual Information Form and the materials listed in the preceding paragraph are available on the foregoing basis and upon request by contacting the Corporation at its offices at Suite 900, 520 – 3rd Avenue S.W., Calgary, Alberta T2P 0R3, by phone at (403) 403 218-2063, fax at (403) 218-2064 or email at general.info@veroenergy.ca.

SCHEDULE "A"

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

Management of Vero Energy Inc. (the "Company") is responsible for the preparation and disclosure of information with respect to Vero'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, 2011 estimated using forecast prices and costs:

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

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

(a) reviewed the procedures of the Company for providing information to the independent qualified reserves evaluator;

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

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

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

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing the reserves data and other oil and gas information;

(b) the filing of Form 45-101F1 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

DATED as of this 30th day of March, 2012.

(signed) "*Douglas J. Bartole*"
Douglas J. Bartole
President and Chief Executive Officer

(signed) "*Gerald Gilewicz*"
Gerald Gilewicz
Vice-President, Finance and Chief Financial Officer

(signed) "*Clinton T. Broughton*"
Clinton T. Broughton
Director and Chairman of the Reserves Committee

(signed) "*Paul R. Baay*"
Paul R. Baay
Director and member of the Reserves Committee

SCHEDULE "B"

FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS

To the board of directors of Vero Energy Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011 estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10%, included in the reserves data of the Company evaluated by us as of December 31, 2011, 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	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$))			
			Audited	Evaluated	Reviewed	Total
Sproule	Evaluation of the PN&G Reserves of Vero Energy Inc. as of December 31, 2011, prepared November 2011 to March 2012	Canada	Nil	395,995	Nil	395,995

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are presented in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we have reviewed but did not audit or evaluate.

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 judgements regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

Sproule Associates Limited, Calgary, Alberta, Canada, March 5, 2012

Per: "Signed"
Robert R. Warholm, P.Eng.
Manager, Engineering and Associate

Per: "Signed"
Ian K. Kirkland, P. Geol.
Senior Petroleum Engineer and Associate

Per: "Signed"
Cameron P. Six, P. Eng.
Vice-President, Engineering and Partner

SCHEDULE "C"

VERO ENERGY INC.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

Role and Objective

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

The primary objectives of the Committee are as follows:

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

To provide better communication between directors and external auditors;

To enhance the external auditor's independence;

To increase the credibility and objectivity of financial reports; and

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

Membership of Committee

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

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

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

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

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

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

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

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

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

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

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

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

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

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

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

Maintain and administer the Corporation's "whistleblower" policy.

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

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

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

Meetings and Administrative Matters

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

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

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

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

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

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

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

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

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

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

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