



Annual Information Form
Year Ended December 31, 2011

March 21, 2012

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SCHEDULE "A"	FORM 51-101F3 REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE
SCHEDULE "B"	FORM 51-101F2 REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATORS
SCHEDULE "C"	AUDIT COMMITTEE CHARTER

ABBREVIATIONS

Crude Oil and Natural Gas Liquids

Bbls	barrels
Bbls/d	barrels per day
Mbbls	thousand barrels
BOE/Boe	barrels of oil equivalent of natural gas (on the basis of 6 Mcf of natural gas to 1 bbl of oil)
Boe/d	barrels of oil equivalent per day
Mboe	thousand Boe
NGLs	natural gas liquids
Mmbtu	million British thermal units
Mstb	thousand stock tank barrels
Stb	stock tank barrel

Natural Gas

Bcf	billion cubic feet
Mcf	thousand cubic feet
Mmcf	million cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
GJ	gigajoule

Other

AECO	The natural gas storage facility located at Suffield, Alberta
LSD	Legal site description
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CONVERSION

<u>To Convert From</u>	<u>To</u>	<u>Multiply By</u>
Mcf	cubic metres	28.174
Thousand cubic metres	Mcf	35.494
Bbls	Cubic metres ("m ³ ")	0.159
Cubic metres	bbls	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, expected levels of activity, budgeted capital expenditures and the method of funding thereof, drilling, completion and tie-in plans, productive capacity of wells, expected royalty rates and changes to the royalty regime and the possible effect thereof on us 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, estimated drilling costs of test wells and the timing thereof, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates and estimated production rates, changes in royalty rates and expenses, environmental risks, partner risk and 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, changes in the regulatory and taxation environment, 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 our 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 are based on a number of factors and assumptions which have been used to develop such statements but which may prove to be incorrect. Although we believe that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because we 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 we operate; the timely receipt of any required regulatory approvals; our ability 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 we have an interest in to operate the field in a safe, efficient and effective manner; our the ability 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 our ability 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 we operate; and our ability to successfully market our 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 affect our operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website www.sedar.com and at our website www.pinecrestenergy.com. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and we assume 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 our 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 we believe to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While we are 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.

GLOSSARY

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

Entities

Antler Creek means Antler Creek Energy Corp., our previous name.

BEC means Batoche Energy Corp., a corporation incorporated under the ABCA, which was amalgamated on May 31, 2009 to form us.

BEC-G means Batoche Energy (Griffen) Corp, a corporation incorporated under the ABCA, which assigned all of its assets to us on June 1, 2009 and was dissolved on October 29, 2009.

BEC-H means Batoche Energy (Heward) Corp, a corporation incorporated under the ABCA, which assigned all of its assets to us on June 1, 2009 and was dissolved on October 29, 2009.

Pinecrest, we, us, our means Pinecrest Energy Inc., a corporation amalgamated under the ABCA.

Testudo means Testudo Oil & Gas Exploration Ltd., a corporation incorporated under the ABCA, which subsequently amended its Articles to change its name to "Antler Creek Energy Corp." and which then amalgamated with BEC.

Independent Engineering

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.

CSA 51-324 means Staff Notice 51-324 – Glossary to NI 51-101 *Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators*.

Sproule means Sproule & Associates Ltd.

Sproule Report means report of Sproule dated March 19, 2012 evaluating our crude oil, natural gas liquids and natural gas reserves as at December 31, 2011.

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

Securities and Other

ABCA means the *Business Corporations Act* (Alberta) together with any or all regulations promulgated thereunder, as amended from time to time;

Common Shares means our common shares, as presently constituted.

GAAP means: (i) with respect to financial years beginning after January 1, 2011, the generally accepted accounting principles in Canada of publically accountable enterprises; and (ii) with respect to financial years beginning before January 1, 2011, the generally accepted accounting principles, in each case as set by the Canadian Institute of Chartered Accountants and as permitted by National Instrument 52-107 *Financial Disclosure*, for the preparation of financial statements.

NI 51-102 means National Instrument 51-102 – *Continuous Disclosure Obligations*.

Qualifying Transaction means a transaction where a capital pool company acquires by way of purchase, amalgamation, merger or arrangement with another company, one or more assets or

businesses which, when purchased, optioned or otherwise acquired by the capital pool company together with any other concurrent transaction, would result in the capital pool company meeting the minimum listing requirements of the TSXV.

Shareholders means the holders of our Common Shares from time to time.

TSXV means the TSX Venture Exchange.

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

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

CONVENTIONS

Certain terms used herein are defined in the "Glossary". Certain other terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "\$" or "dollars" are to Canadian dollars. All financial information has been presented in Canadian dollars in accordance with applicable GAAP in Canada.

BARREL OF OIL EQUIVALENCY

The term "BOE" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet per barrel (6 Mcf: 1 Bbl) of natural gas to barrels of oil equivalence 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 compares 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.

NON-GAAP MEASURES

We use the following terms for measurement within this Annual Information Form that do not have a standardized prescribed meaning under GAAP and these measurements may differ from other companies and accordingly may not be comparable to measures used by other companies. The terms "funds flow from operations", "funds flow from operations per share", "operating netback" and "cash flow netback" in this Annual Information Form are not recognized measures under GAAP. Management believes that these terms are useful, in addition to net earnings and cash flow from operating activities as defined by GAAP, for evaluating our operating performance and leverage. Funds flow from operations is expressed as cash flow from operating activities before changes in non-cash working capital and decommissioning expenditures. Operating netback is a measure of operating margin used in capital allocation decisions. We define operating netback as average realized price per BOE, less royalties per BOE, less operating and transportation expenses per BOE, plus any realized gain or loss per BOE on financial instruments. Cash flow netback is a measure of operating netback plus other operating income less net cash administrative expenses, less cash interest expenses. We define corporate netback as operating netback plus other income per BOE less general and administrative expenses per BOE less interest expense per BOE. ***Readers are cautioned that these measures should not be construed as an alternative to net earnings, or cash flow from operating activities as calculated under GAAP as an indication of our performance.***

PINECREST ENERGY INC.

We are a junior oil and gas company involved in the exploration, development and production of oil and gas activities in Alberta and Saskatchewan. Our head office is located at Suite 500, 255 - 5th Avenue SW, Calgary, Alberta T2P 3G6 and our records and registered office is located at Suite 2400, 525 - 8th Avenue SW, Calgary, Alberta T2P 1G1. Our Common Shares trade on the TSXV under the symbol "PRY".

We were originally incorporated under the ABCA on March 24, 2006 under the name "Testudo Oil & Gas Exploration Ltd." as a capital pool company pursuant to the policies of the TSXV. On May 22, 2009, we amended our articles to change our name to "Antler Creek Energy Corp." On May 31, 2009, we amalgamated with BEC and continued under the name "Antler Creek Energy Corp." Following the amalgamation, steps were taken to wind-up both of BEC's wholly-owned subsidiaries, BEC-G and BEC-H and dissolution of both occurred on October 29, 2009.

On May 6, 2010, we completed the Capitalization Transaction (as defined herein), and on July 22, 2010 at an annual and special meeting of Shareholders we amended our articles changing our name to "Pinecrest Energy Inc."

GENERAL DEVELOPMENT OF THE BUSINESS

History and Development

Year Ended July 31, 2009

On September 25, 2008, we entered into a definitive agreement with BEC, its wholly-owned subsidiary, BEC-G, and fourteen other legal entities. The definitive agreement, as amended provided that we would purchase a ten percent (10%) working interest in Section 13-8-11-W2M from BEC-G. and a ten percent (10%) working interest in certain lands in Griffin, Saskatchewan from BEC. The consideration to be paid by us for the BEC-G and BEC working interests was an aggregate of \$1,200,000 plus GST. On April 30, 2009 we entered into a share purchase agreement, which superseded and replaced in its entirety the first definitive agreement. Pursuant to the share purchase agreement we acquired all of the issued and outstanding shares of BEC for the aggregate purchase price of \$2,100,000.

Concurrently with the closing of the BEC purchase and in order to fund the purchase price of the BEC shares, we completed a financing and issued 603,666 Common Shares on a "flow-through" basis under the *Income Tax Act* (Canada) at a price of \$0.45 per flow-through share and 748,334 units at a price of \$0.45, with each unit comprised of one Common Share and one Common Share purchase warrant. The financing together with the acquisition of the BEC shares constituted our Qualifying Transaction.

On May 31, 2009, we amalgamated with our then wholly-owned subsidiary BEC and carried on under the name "Antler Creek Energy Corp." Following the amalgamation, on June 1, 2009 the assets of BEC's subsidiaries were assigned to us and steps were taken to wind up BEC-G and BEC-H, and dissolution of each was completed on October 29, 2009.

The acquisition of the shares of BEC constituted a significant acquisition under Part 8 of NI 51-102. For further information on the acquisition of BEC, please refer to the business acquisition report dated May 6, 2010, a copy of which can be found on our SEDAR profile at www.sedar.com.

Year Ended July 31, 2010

Capitalization Transaction

On April 25, 2010, we entered into a definitive capitalization and investment agreement (the "**Capitalization Agreement**") with an investor group including Wade Becker, Dan Toews, Bill Turko and Korby Zimmerman, which provided the terms for a non-brokered private placement and the appointment of a new management team and a new Board of Directors (collectively the "**Capitalization**

Transaction"). Pursuant to the Capitalization Agreement the new management team and the new Board of Directors were appointed on May 6, 2010. The financing closed in two successive closings effective May 6, 2010 and May 21, 2010, respectively, with the issuance of a total of 53,042,340 Common Shares and 34,258,530 common share purchase warrants ("**Purchase Warrants**") amounting to aggregate gross proceeds of approximately \$20 million. Each Purchase Warrant entitles the holder to purchase one Common Share at an exercise price of \$0.50 for a period of five years from the date of issuance subject to certain Common Share performance criteria being satisfied.

Each person who became one of our directors or officers following completion of the Capitalization Transaction and who subscribed for securities thereunder agreed to enter into an escrow agreement which provided that 29,428,530 Common Shares, all of the Purchase Warrants and any Common Shares issued on exercise of the Purchase Warrants (as the case may be) were to be subject to a 24 month escrow wherein 25% of such securities shall be released on each of the 6, 12, 18 and 24 month anniversaries of closing of the respective tranche of the financing. There are currently 7,357,138 Common Shares and 7,357,138 Purchase Warrants subject to escrow under the Escrow Agreement. See "*Escrowed Securities*" in this Annual Information Form.

Asset Acquisitions

On July 14, 2010 and July 15, 2010, we acquired certain assets for aggregate purchase price of \$18.1 million (including closing adjustments), all of which are located in our greater Red Earth core focus area. In total, we acquired 21,627 gross acres (13,150 net) of land located in the heart of the emerging Slave Point formation light oil resource play. On August 30, 2010 we filed a business acquisition report as this transaction constituted a "significant acquisition" under Part 8 of NI 51-102. The business acquisition report can be viewed on our SEDAR profile at www.sedar.com.

July Offering

On July 7, 2010, we issued an aggregate of 24.05 million Common Shares at a price of \$1.04 per Common Share for aggregate proceeds of approximately \$25 million by way of short form prospectus, through a syndicate of underwriters. The underwriters exercised their over-allotment option and on July 9, 2010 and consequently we issued an additional 3,607,500 Common Shares at a price of \$1.04 per share for aggregate gross proceeds of \$3,751,800.

Year Ended December 31, 2010

Fall Offerings

On September 15, 2010, we issued an aggregate of 25 million Common Shares at a price of \$1.40 per Common Share for aggregate proceeds of \$35 million by way of short form prospectus through a syndicate of underwriters. We also granted the underwriters an over-allotment option to purchase up to an additional 3,750,000 Common Shares at a price of \$1.40 per share on the same terms and conditions, exercisable at any time, in whole or in part for a period of 30 days following closing. As a partial exercise of the over-allotment option, we issued an additional 3,663,143 common shares at a price of \$1.40 per share for aggregate proceeds of \$5,128,400 on October 12, 2010.

On November 16, 2010, we issued an aggregate of 48.4 million Common Shares at a price of \$1.55 per Common Share for aggregate proceeds of \$75.02 million by way of short form prospectus through a syndicate of underwriters. We also granted the underwriters an over-allotment option to purchase up to an additional 7.26 million Common Shares at a price of \$1.55 per share on the same terms and conditions, exercisable at any time, in whole or in part for a period of 30 days following closing. On November 16, 2010, with a full exercise of the over-allotment option, we issued an additional 7.26 million common shares at a price of \$1.55 per share for aggregate proceeds of \$11,253,000.

Change of Year End

On October 16, 2010, we received approval from the Canada Revenue Agency and subsequently, on November 25, 2010, we filed a notice under Part 4.8 of NI 51-102 providing for the change of our financial year end from July 31 to December 31.

Year Ended December 31, 2011

Summer Offering

On August 24, 2011, we issued an aggregate of 25 million Common Shares at a price of \$2.40 per Common Share for aggregate gross proceeds of \$60 million by way of a short form prospectus through a syndicate of underwriters.

Significant Acquisitions

No significant acquisitions were completed during the year ended December 31, 2011 for which discussion is required under Part 8 of NI 51-102.

Recent Developments

On January 12, 2012, the borrowing base of Pinecrest's credit facility with a Canadian Chartered bank was increased to \$75 million.

On March 14, 2012, we issued 18.5 million Common Shares at a price of \$3.25 per Common Share for aggregate gross proceeds of \$60.125 million by way of a short form prospectus through a syndicate of underwriters.

Significant Acquisitions

No significant acquisitions were completed during the year ended December 31, 2011 for which discussion is required under Part 8 of NI 51-102.

GENERAL DESCRIPTION OF THE BUSINESS

Our business plan is to focus on sustainable and profitable per share growth in both cash flow from operating activities and net asset value. Our key strategies are to:

- (a) focus on oil production and reserves from a large operated land base and a portfolio of drilling locations based on our use of seismic data and geological reports;
- (b) exploit the low risk development drilling opportunities where we have existing infrastructure; and
- (c) seek acquisitions consistent with this strategic focus and in areas where the management team has experience and expertise.

We have been concentrating in assembling a significant land position in the Greater Red Earth/Slave Point play, and we are now focused on the execution of a capital program to organically grow our reserves, production and cash flow per share. Our management team and our Board of Directors have been focused on the identification, evaluation and acquisition of high working interest, operated lands and the successful execution of this plan has resulted in us assembling a large land position, a significant drilling inventory and strategic producing infrastructure in the heart of the Slave Point light oil resource play.

Revenue Sources

For the year ended December 31, 2011, 99% of the revenue (before royalties) from our properties was derived from crude oil and 1% was derived from natural gas and natural gas liquids. Our results and financial condition are dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. For more information please review our financial statements and management's discussion and analysis for the year ended December 31, 2011, available for review on our SEDAR page at www.sedar.com. We mitigate such price risk by closely monitoring the various commodity markets and establishing price risk management programs, as deemed necessary and through maintaining financial flexibility. See also "*Risk Factors – Prices, Markets and Marketing*" and "*Risk Factors – Hedging*".

Seasonal Considerations

All of our properties are accessible year round, except during spring break up. Major facilities through which our production is processed may temporarily be shut down for short periods of time during the year to conduct repair and maintenance operations.

Environmental Matters

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal regulations. Compliance with such regulation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness.

Our operations are, and will continue to be affected in varying degrees by laws and regulations regarding environmental protection. We are committed to meeting our responsibilities to protect the environment and we will take such steps as required to ensure compliance with environmental legislation in all jurisdictions in which we operate. We believe that it is reasonably likely that the trends towards stricter standards in environmental legislation and regulation will continue and we anticipate making increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment. However, it is not currently possible to quantify any such increased expenditures and it is not anticipated that our competitive position will be adversely affected by current or future environmental laws and regulations governing our oil and natural gas operations. See "*Industry Conditions – Environmental Regulatory*" and "*Industry Conditions – Climate Change Regulation*".

Competitive Conditions

There is strong competition relating to all aspects of the oil and natural gas industry. We actively compete for capital, skilled personnel, undeveloped lands, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of our operations with a substantial number of other organizations, many of which have greater technical and financial resources than us. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a worldwide basis and have greater and more diverse resources upon which to draw.

Specialized Skill and Knowledge

The Corporation relies on specialized skills and knowledge to gather, interpret and process geophysical data; drill and complete wells; design and operate production facilities and numerous additional activities required to explore for and produce oil and natural gas. The Corporation has employed a strategy of contracting consultants and other service providers to supplement the skills and knowledge of its

permanent staff in order to provide the specialized skills and knowledge to undertake its oil and natural gas operations effectively.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2012 by the renegotiation or termination of contracts or subcontracts.

In early 2012, Pinecrest received an increase in its credit facility with a Canadian chartered bank to \$75 million from the previous limit of \$30 million.

Reorganizations

Other than the Capitalization Transactions described above under "History and Development", there have been no other reorganizations of the Corporation in the last three years and no reorganizations are proposed for the current financial year.

Human Resources

As at December 31, 2011, we had 18 full time employees and 2 other part time consultants. See "*Directors and Officers*".

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below is dated March 19, 2012 and the effective date of the data is December 31, 2011.

Disclosure of Reserves Data and Other Information

The reserves data set forth below is based upon an evaluation by Sproule with an effective date of December 31, 2011 contained in the Sproule Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. 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. We engaged Sproule to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of our reserves are in Canada and, specifically, in the provinces of Alberta and Saskatchewan.

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

All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the Sproule Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. The recovery and reserve estimates on our properties described herein are estimates only. The actual reserves on our properties may be greater or less than those calculated. See "*Risk Factors*" in this Annual Information Form.

Reserves Data (Forecast Prices and Costs)

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

RESERVES CATEGORY	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross (Mbbbls)	Net (Mbbbls)	Gross (Mbbbls)	Net (Mbbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbbls)	Net (Mbbbls)
PROVED:								
Developed Producing	3,768.1	3,141.9	0.0	0.0	83	68	13.0	10.5
Developed Non-Producing	204.0	174.3	0.0	0.0	7	6	1.0	0.9
Undeveloped	1,187.9	1,026.7	0.0	0.0	414	393	62.2	59.0
TOTAL PROVED	5,160.0	4,342.9	0.0	0.0	504	466	76.2	70.4
PROBABLE	2,977.7	2,335.2	0.0	0.0	279	260	42.2	39.2
TOTAL PROVED PLUS PROBABLE	8,137.6	6,678.0	0.0	0.0	784	726	118.4	109.7

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)					UNIT VALUE
	0%	5%	10%	15%	20%	10%
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(\$/BOE)
PROVED:						
Developed Producing	225,170	178,018	151,373	134,215	122,123	47.85
Developed Non-Producing	12,440	10,124	8,773	7,878	7,229	49.79
Undeveloped	45,746	28,074	18,469	12,435	8,261	16.04
TOTAL PROVED	283,356	216,216	178,616	154,528	137,613	39.77
PROBABLE	175,815	92,486	61,153	45,370	35,827	25.29
TOTAL PROVED PLUS PROBABLE	459,170	308,702	239,769	199,898	173,440	34.71

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0%	5%	10%	15%	20%
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
PROVED:					
Developed Producing	225,170	178,018	151,373	134,215	122,123
Developed Non-Producing	12,440	10,124	8,773	7,878	7,229
Undeveloped	38,550	24,728	16,586	11,178	7,302
TOTAL PROVED	276,160	212,870	176,732	153,270	136,653
PROBABLE	132,030	69,394	45,706	33,615	26,177
TOTAL PROVED PLUS PROBABLE	408,190	282,263	222,438	186,885	162,831

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS ⁽¹⁾⁽²⁾**

RESERVES CATEGORY	REVENUE (M\$)	ROYALTIES (M\$)	OPERATING COSTS (M\$)	DEVELOPMENT COSTS (M\$)	ABANDONMENT AND RECLAMATION COSTS (M\$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M\$)	INCOME TAXES (M\$)	FUTURE NET REVENUE AFTER INCOME TAXES (M\$)
Total Proved	547,672	83,984	141,412	35,891	3,031	283,356	7,196	276,160
Total Proved plus Probable	921,447	157,487	241,679	59,052	4,058	459,170	50,981	408,190

Notes:

- (1) Total revenue includes company revenue before royalty and includes other income, net of transportation costs.
- (2) Royalties include Crown, freehold and overriding royalties and mineral tax.

**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) (M\$)	UNIT VALUE BEFORE INCOME TAXES (discounted at 10%/year) (\$/Boe) ⁽¹⁾
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	178,616	39.77
	Heavy Oil (including solution gas and other by-products)	0	0
	Natural Gas (including by-products but excluding natural gas from oil wells)	0	0
	Total	178,616	39.77
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	239,769	34.71
	Heavy Oil (including solution gas and other by-products)	0	0
	Natural Gas (including by-products but excluding natural gas from oil wells)	0	0
	Total	239,769	34.71

Notes:

- (1) Unit Values are based on net reserve volumes.

Definitions and Notes to Reserves Data Tables:

In the tables set forth above in "Reserves Data (Forecast Prices and Costs)" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. **"Gross" or "gross"** means:
 - (i) in relation to our interest in production and reserves which are our working interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interest;
 - (ii) in relation to wells, the total number of wells in which we have an interest; and
 - (iii) in relation to properties, the total area of properties in which we have an interest;
2. **"Net" or "net"** means:
 - (i) in relation to our interest in production and reserves, our working interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interests in production or reserves;
 - (ii) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
 - (iii) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest we own;
3. **Definitions used for reserves categories are as follows:**

Reserve Categories

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

- (i) analysis of drilling, geological, geophysical and engineering data;
- (ii) the use of established technology; and
- (iii) specified economic conditions, specifically the forecast prices and costs.

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

- (i) **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.
- (ii) **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:

- (i) **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.
- (ii) **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.
- (iii) **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.
- (iv) **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:

- (i) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
- (ii) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods. Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

- 4. **"Exploratory well"** means a well that is not a development well, a service well or a stratigraphic test well.
- 5. **"Development costs"** means costs incurred to obtain access to our reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from our reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

- (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;
 - (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;
 - (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and
 - (d) provide improved recovery systems.
- 6. **"Development well"** means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.
- 7. **"Exploration costs"** means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
 - (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;
 - (b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
 - (c) dry hole contributions and bottom hole contributions;
 - (d) costs of drilling and equipping exploratory wells; and
 - (e) costs of drilling exploratory type stratigraphic test wells.
- 8. **"Service well"** means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.
- 9. **"Forecast Prices and Costs"**

These are prices and costs that are:

 - (a) generally acceptable as being a reasonable outlook of the future; and
 - (b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are 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).

10. Numbers may not add due to rounding.
11. The estimates of future net revenue presented in the tables above do not represent fair market value.
12. We do not have any synthetic oil or other products from non-conventional oil and gas activities.

Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the Sproule Report were Sproule's forecasts, as at December 31, 2011, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS FORECAST PRICES AND COSTS ⁽¹⁾								
Year	OIL			NATURAL GAS	NATURAL GAS LIQUIDS		INFLATION RATE %/Year ⁽²⁾	EXCHANGE RATE (\$US/\$Cdn) ⁽³⁾
	WTI Cushing Oklahoma (\$US/Bbl)	Edmonton Par Price 40° API (\$Cdn/ Bbl)	Cromer Medium 29.3° API (\$Cdn/ Bbl)	AECO Gas Price (\$Cdn/ MMbtu)	Pentanes Plus FOB Field Gate (\$Cdn/Bbl)	Butanes FOB Field Gate (\$Cdn/Bbl)		
Forecast								
2012	98.07	96.87	90.09	3.16	103.57	72.20	2.0	1.012
2013	94.90	93.75	87.19	3.78	100.23	69.87	2.0	1.012
2014	92.00	90.89	84.52	4.13	97.17	67.74	2.0	1.012
2015	97.42	96.23	89.50	5.53	102.89	71.73	2.0	1.012
2016	99.37	98.16	91.29	5.65	104.94	73.16	2.0	1.012
2017	101.35	100.12	93.11	5.77	107.04	74.63	2.0	1.012
2018	103.38	102.12	94.98	5.89	109.18	76.12	2.0	1.012
2019	105.45	104.17	96.88	6.01	111.37	77.64	2.0	1.012
2020	107.56	106.25	98.81	6.14	113.59	79.19	2.0	1.012
2021	109.71	108.38	100.79	6.27	115.87	80.78	2.0	1.012

Notes:

- (1) As at December 31, 2011.
- (2) Inflation rate for forecasting prices and costs.
- (3) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical price realized by us for the year ended December 31, 2011 was \$95.58/bbl for crude oil and NGLs and \$3.68 /Mcf for natural gas.

Estimated future abandonment costs related to a working interest have been taken into account by Sproule in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for reclamation of wellsites or the abandonment of any facilities. 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 were accepted by Sproule as represented. No field inspection was conducted. Reconciliation of Changes in Reserves and Future Gross Revenue.

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

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS						
	LIGHT AND MEDIUM OIL ⁽¹⁾			ASSOCIATED AND NON-ASSOCIATED AND SOLUTION GAS		
	Gross Proved (Mbbbls)	Gross Probable (Mbbbls)	Gross Proved Plus Probable (Mbbbls)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
December 31, 2010	1,036.4	674.2	1,710.6	239	88	327
Extensions	4,575.0	2,454.6	7,029.6	292	189	481
Infill Drilling	0.0	0.0	0.0	0	0	0
Technical Revisions	37.2	(148.7)	(111.5)	(17)	3	(14)
Discoveries	0.0	0.0	0.0	0	0	0
Acquisitions	0.0	0.0	0.0	0	0	0
Dispositions	(6.7)	(2.6)	(9.3)	0	0	0
Economic Factors	4.8	0.1	4.9	2	0	3
Production	(486.7)	0.0	(486.7)	(12)	0	(12)
December 31, 2011	<u>5,160.0</u>	<u>2,977.6</u>	<u>8,137.6</u>	<u>504</u>	<u>280</u>	<u>784</u>

	NATURAL GAS LIQUIDS			TOTAL RESERVES		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2010	30.4	10.8	41.2	1,106.6	699.7	1,806.3
Extensions	50.1	31.1	81.2	4,673.8	2,517.2	7,191.0
Infill Drilling	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	(1.6)	0.3	(1.3)	32.8	(147.9)	(115.1)
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	(6.7)	(2.6)	(9.3)
Economic Factors	0.2	0.0	0.2	5.3	0.1	5.6
Production	(2.9)	0.0	(2.9)	(491.6)	0.0	(491.6)
December 31, 2011	<u>76.2</u>	<u>42.2</u>	<u>118.4</u>	<u>5,320.2</u>	<u>3,066.4</u>	<u>8,386.6</u>

Note:

(1) The Company does not have any Heavy Oil Reserves

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In general, once proved and/or probable undeveloped reserves are identified they are scheduled into our development plans. We plan to develop our proved and probable undeveloped reserves within two years. In some cases, it will take longer than two years to develop these reserves. As such, we expect that the large majority of our booked undeveloped projects will be completed within a two year time frame. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "Risk Factors".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years and, in the aggregate, before that time.

Year	Light and Medium Oil (Mbbls)		Heavy Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
July 31, 2010	97.5	97.5	0.0	0.0	33	33	5.2	5.2
Dec. 31, 2010	98.8	196.3	0.0	0.0	9	42	1.3	6.5
Dec. 31, 2011	1,132.9	1,187.9	0.0	0.0	79	414	25.2	62.2

Sproule has assigned 1,319.1 MBOE of proved undeveloped reserves in the Sproule Report together with \$35.5 million in undiscounted future capital attributed to proved undeveloped reserves to be spent in the next two years.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

Year	Light and Medium Oil (Mbbbls)		Heavy Oil (Mbbbls)		Natural Gas (MMcf)		NGLs (Mbbbls)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
July 31, 2010	217.3	217.3	0.0	0.0	73	73	11.7	11.7
Dec. 31, 2010	206.1	299.7	0.0	0.0	9	16	1.4	2.5
Dec. 31, 2011	1428.4	1450.1	0.0	0.0	86	233	27.2	35.0

Sproule has assigned 1,523.9 MBOE of probable undeveloped reserves in the Sproule Report together with \$23.2 million in undiscounted future capital attributed to probable undeveloped reserves to be spent in the next five years.

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 year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

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

Future Development Costs

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

Year	FORECAST PRICES AND COSTS	
	Proved Reserves (\$000s)	Proved Plus Probable Reserves (\$000s)
2012	35,891	59,052
2013	0	0
2014	0	0
2015	0	0
2016	0	0
Remaining	0	0
Total (Undiscounted)	35,891	59,052

The future development costs are capital expenditures required in the future for us to convert proved undeveloped reserves and probable reserves to proved developed producing reserves. The undiscounted development costs are \$35.9 million for proved reserves and \$59.1 million for proved plus probable reserves (in each case based on forecast prices and costs).

On an ongoing basis, we will use internally generated cash flow from operations, debt and new equity issues, if available on favourable terms, to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic.

Other Oil and Gas Information

Principal Properties

We operate in two core areas, Greater Red Earth, Alberta and southeast Saskatchewan, all of which are reviewed in the Sproule Report. The following is a description of our principal oil and gas properties as at December 31, 2011.

Alberta – Greater Red Earth

Evi/Otter Properties

The Evi/Otter Properties are located in northern Alberta in townships 86-88, ranges 10-12 west of the fifth meridian. The Evi/Otter Properties consist of 98 (41.5 net) oil wells, of which we operate 39. Of the total wells, 81 are currently producing (39 operated by Pinecrest); from either the Slave Point formation or the Granite Wash formation and 3 from commingled Slave Point and Granite Wash. Pinecrest operates most of the production in this area as well as the Evi 11-4-87-11W5M central battery. Field production is either gathered via effluent flowlines to the 11-4-87-11W5 battery or is trucked from single well batteries to the central battery where oil and water are separated, water is disposed of and oil is shipped to sales.

Production from the Evi/Otter properties for the year ended December 31, 2011 averaged 1,069 Boe/d net, 99% of which is light sweet crude oil.

Red Earth Properties

The Red Earth Properties are located in northern Alberta in townships 87-89, ranges 7-8 west of the fifth meridian. The Red Earth Properties consist of 28 (19.0 net) oil wells, 18 of which are operated by Pinecrest. Of these gross wells, 15 are currently producing (11 operated by Pinecrest); from either the Slave Point formation or the Granite Wash formation. Field production is either gathered via effluent

flowlines to third party processing facilities or is trucked from single well batteries to either our Evi 11-04-87-11W5 battery or our Ogston 10-32-89-11W5M battery, or to third party processing facilities where oil and water are separated, water is disposed of and oil is shipped to sales.

Production from the Red Earth properties for the year ended December 31, 2011 averaged 53 Bbls/d net, 100% of which is light sweet crude oil.

Loon Properties

The Loon Properties are located in northern Alberta in townships 84-86, ranges 8-9 west of the fifth meridian. The Loon Properties consist of 49 (9.72 net) oil wells, 6 of which are operated by Pinecrest. Of the total wells, 39 are currently producing from either the Slave Point formation or from the Granite Wash formation. Field production is either gathered via effluent flowlines to third party processing facilities or is trucked from single well batteries to either our Evi 11-04-887-11W5 battery or our Ogston 10-32-89-11W5M battery or to third party processing facilities where oil and water are separated, water is disposed of and oil is shipped to sales.

Production from the Loon Properties for the year ended December 31, 2011 averaged 77 Bbls/d net, 100% of which is light sweet crude oil.

Ogston Properties

The Ogston Properties are located in northern Alberta in townships 89-90, ranges 10-11 west of the fifth meridian. The Ogston Properties consist of 20 (13.1 net) oil wells, of which we operate 15. Of the total wells, 9 are currently producing, all from the Granite Wash formation. Field production is gathered via effluent flowlines to our operated 10-32-89-11W5 central battery where oil and water are separated, water is disposed of and oil is trucked to sales.

Production from the Ogston Properties for the year ended December 31, 2011 averaged 21 Bbls/d net, 100% of which is light sweet crude oil (solution gas is not conserved).

Saskatchewan - Southeast

Viewfield Properties

The Viewfield Properties are located in southeast Saskatchewan, approximately 130 kilometres southeast of the city of Regina, in townships 8-10, ranges 9-11 west of the second meridian. The Viewfield Properties consist of 15 (6.0 net) oil wells, 12 of which are currently producing. Pinecrest operates 7 of the 15 wells in this area and all but 2 wells are horizontally drilled targeting the Bakken formation. Field production is either gathered via effluent flowlines to third party processing facilities or is trucked from single well batteries to third party processing facilities where oil and water are separated, water is disposed of and oil is shipped to sales.

Production from the Viewfield properties for the year ended December 31, 2011 averaged 128 Boe/d net, 95% of which is light crude oil.

Oil and Gas Wells

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

	Oil Wells				Natural Gas Wells			
	Producing ⁽¹⁾		Non-Producing ⁽²⁾		Producing		Non-Producing	
	Gross ⁽³⁾	Net ⁽⁴⁾	Gross	Net	Gross	Net	Gross	Net
Alberta	144	54.5	49	28.4	1	-	1	0.3
Saskatchewan	12	4.0	3	1.9	-	-	-	-
Total	156	58.5	52	30.3	1	-	1	0.3

Notes:

- (1) Includes wells that are temporarily shut-in but which are capable of production.
- (2) Includes wells that are not capable of production, but that are not yet abandoned.
- (3) Gross means number of wells in which Pinecrest has a working interest
- (4) Net means the number of wells obtained by multiplying Pinecrest's working interest percentage held therein.

Properties with No Attributable Reserves

The following table sets out our developed and undeveloped land holdings as at December 31, 2011.

	DEVELOPED ACRES		UNDEVELOPED ACRES		TOTAL ACRES	
	Gross	Net	Gross	Net	Gross	Net
Alberta	12,760	7,367	110,387	107,064	123,147	114,431
Saskatchewan	1,923	641	2,688	2,288	4,611	2,929
Total	14,683	8,008	113,075	109,352	127,758	117,360

At December 31, 2011 we had 113,075 gross (109,352 net) acres of undeveloped land holdings, consisting of 110,387 gross (107,064 net) acres in the Province of Alberta and 2,688 gross (2,288 net) acres in the Province of Saskatchewan. Rights to explore and develop 2,617 net acres of our undeveloped land holdings could expire by December 31, 2012 if not continued.

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

Forward Contracts and Marketing

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by us to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. Subsequent to December 31, 2011, Pinecrest entered into four commodity price risk contracts which fix the price received per barrel as follows:

COMMODITY	TYPE	TERM	VOLUME	PRICE PER BBL (CDN\$)	INDEX
Oil	Swap	Jan 1/12 – Dec 31/12	500 bbl/d	\$92.20	WTI
Oil	Swap	Jan 1/12 – Dec 31/12	200 bbl/d	\$97.75	WTI
Oil	Swap	Jan 1/12 – Dec 31/12	500 bbl/d	\$103.50	WTI
Oil	Swap	Feb 1/12 – Dec 31/12	300 bbl/d	\$100.00	WTI

Additional Information Concerning Abandonment Costs

The following table sets forth information about future abandonment costs for wells for which reserves have been assigned in the Sproule Report and that are expected to be incurred by the Company for the years indicated in the forecast prices and costs case of that report.

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted (\$000s)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% (\$000s)
Total liability as at December 31, 2011	4,058	329
Anticipated to be paid in 2012	0	0
Anticipated to be paid in 2013	15	12
Anticipated to be paid in 2014	33	25

Estimated costs of abandonment were included in the Sproule Report as a deduction in determining future net revenue. The total estimated abandonment costs in respect of proved reserves using forecast prices is \$3.0 million undiscounted (\$0.5 million using a 10% discount rate). The full amount of such values were deducted as abandonment costs in estimating our future net revenue in respect of proved reserves as disclosed above. No allowance for salvage value was included in these costs. The total proved plus probable abandonment and reclamation costs are \$4.1 million undiscounted and \$0.3 million (discounted at 10%).

We estimate well abandonment costs on an area by area basis using historical costs which are supplemented by current industry costs and changes in regulatory requirements. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. As at December 31, 2011, we had 53 gross (30.6 net) wells for which we expect to incur abandonment costs.

The future net revenues disclosed in this Annual Information Form based on the Sproule Report do not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. We expect to pay, in aggregate, abandonment and reclamation costs of approximately \$516,000 over the next three financial years.

Tax Horizon

Based on our available tax pools, expected capital expenditures and forecast net income for 2012, we do not anticipate paying current income taxes in 2012. Depending on levels of production, commodity prices, acquisitions and capital expenditures, we may begin paying current income taxes in 2013 or beyond.

Capital Expenditures

The following table summarizes capital expenditures related to our activities for the year ended December 31, 2011:

Expenditure	Year Ended December 31, 2011 (\$000s)
Property acquisition costs – Unproved properties ⁽¹⁾	21,498
Property acquisition costs – Proved properties ⁽²⁾	333
Exploration costs ⁽³⁾	1,084
Development costs ⁽⁴⁾	141,957
Other	69
Total	164,941

Notes:

- (1) Cost of land acquired and non-producing lease rentals on those lands
- (2) Net of dispositions
- (3) Geological and geophysical capital expenditures and drilling costs for exploration wells
- (4) Development costs include development drilling, completion and equipping, tie-in and facility costs for all wells

Exploration and Development Activities

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

	Development		Exploratory	
	Gross	Net	Gross	Net
Light and Medium Oil	27	22.8	-	-
Stratigraphic test	-	-	1	1
Standing	1	0.9	-	-
Total	28	23.7	1	1

See "*Principal Properties*" for a description of our exploration and development during the twelve months ended December 31, 2011.

Finding and Development Costs

The following table summarizes our fiscal 2011 finding and development costs.

(\$/BOE)	2011 ⁽¹⁾⁽²⁾⁽³⁾	
	Proved	Proved plus Probable
FD&A costs - excluding crown lands acquired; excluding change in FDC	31.00	20.63
FD&A costs - including crown lands acquired; excluding change in FDC	35.06	23.32
FD&A costs - excluding crown lands acquired; including change in FDC	37.95	28.09
Total FD&A costs - including crown lands acquired; including change in FDC	42.01	30.78

Notes:

- (1) Including changes in future development capital expenditures.
- (2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development capital expenditures generally will not reflect total finding and development costs related to reserves additions for that year.
- (3) Under NI 51-101, the methodology to be used to calculate FD&A costs includes incorporating changes in future development capital ("FDC") required to bring the proved undeveloped and probable reserves to production. For continuity, Pinecrest has presented herein FD&A costs calculated both excluding and including FDC.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2012, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained earlier under the subheading "Disclosure of Reserves Data".

	Light and Medium Oil (Bbls/d)	Heavy Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (Boe/d)
Total Proved					
Evi/Otter	2,312	0	168	25	2,365
Red Earth	474	0	0	0	474
Loon	269	0	0	0	269
Viewfield, SK	84	0	42	7	98
Ogston	26	0	0	0	26
Total	3,165	0	210	32	3,232
Total Proved plus Probable					
Evi/Otter	2,745	0	208	31	2,811
Red Earth	738	0	0	0	738
Loon	374	0	0	0	374
Viewfield, SK	93	0	46	7	108
Ogston	29	0	0	0	29
Total	3,979	0	254	38	4,060

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:

	Quarter Ended 2011 ⁽¹⁾				Year Ended Dec 31 2011
	Dec 31	Sep 30	Jun 30	Mar 31	
Average Daily Production ⁽²⁾					
Light and Medium Oil (Bbls/d)	2,204	1,554	810	748	1,334
Gas (MMcf/d)	51	21	63	1	34
NGL's (Bbls/d)	12	5	9	5	8
Combined (Boe/d)	2,225	1,563	830	753	1,348
Average Prices Received					
Light and Medium Oil (\$/Bbl)	97.77	91.35	104.00	90.30	95.80
Gas (\$/Mcf)	3.43	4.12	4.17	(18.99)	3.68
NGL's (Bbls/d)	53.72	62.24	63.16	58.56	58.69
Combined (\$/Boe)	97.24	91.11	102.55	90.03	95.27
Royalties Paid					
Light and Medium Oil (\$/Bbl)	6.07	10.11	11.60	11.72	8.88
Gas (\$/Mcf)	0.27	0.22	0.13	(5.18)	0.15
NGL's (Bbls/d)	8.38	5.81	1.08	6.58	5.54
Combined (\$/Boe)	6.06	10.08	11.35	11.67	8.82
Production Costs ⁽³⁾⁽⁴⁾ (\$/Boe)	14.79	17.13	21.76	18.04	16.99
Netback Received ⁽⁵⁾ (\$/Boe)	76.39	63.90	69.44	60.32	69.46

Notes:

- (1) In providing information for each product type, allocation among multiple product types attributable to a single well has not been made. The principal product type attributable to the well has been used to categorize the well as either light and medium oil or gas.
- (2) Before deduction of royalties.
- (3) Production costs comprise of direct costs incurred to operate both oil and gas wells and transportation costs to deliver products to market.
- (4) Operating recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.
- (5) Netbacks are calculated by subtracting royalties, transportation and production costs from revenues. Netbacks do not take into account commodity contracts we may have entered into the period.

Our production for the year ended December 31, 2011 was 99% light and medium crude oil, 1% natural gas, and 0% heavy oil.

For the twelve months ended December 31, 2011, approximately 100% of our gross revenue was derived from light and medium oil production and less than 1% of our gross revenue was derived from natural gas and natural gas liquids production.

The following table indicates our average daily production (including production from our major areas) for the year ended December 31, 2011.

	Light and Medium Oil (Bbls/d)	Natural Gas (Mcf/d)	Natural Gas Liquids (Bbls/d)	BOE (Boe/d)
Alberta	1,213	18	4	1,220
Saskatchewan	122	16	4	128
Total	1,334	34	8	1,348

DIRECTORS AND OFFICERS

The following table sets forth the names, municipalities of residence, any offices held with us, the period served as a director and principal occupations of our directors and officers. The term of office of each of our directors expires at the next annual meeting of our Shareholders.

Name and Municipality of Residence and Position	Principal Occupation Past Five Years
Wade Becker Alberta, Canada • <i>President, Chief Executive Officer</i> • <i>Director</i>	Director Since May 7, 2010 Mr. Becker has been our President and Chief Executive Officer since May of 2010. Prior thereto Mr. Becker was President, Chief Executive Officer and Director at Peerless Energy Inc. (a public oil and gas company). Previously Mr. Becker was Vice President, Land and co-founder of both Crescent Point Energy Trust and its predecessor Crescent Point Energy Ltd.
Korby Zimmerman Alberta, Canada • <i>Vice President Business Development and Land</i> • <i>Director</i>	Director Since May 7, 2010 Mr. Zimmerman has been our Vice President, Business Development and Land since May of 2010. Previously, Mr. Zimmerman was Group Leader at EnCana Corporation. Prior to that he was Vice President, Land and Business Development at Ketch Energy Trust

Name and Municipality of Residence and Position	Principal Occupation Past Five Years
John Brussa Alberta, Canada • <i>Non-executive Board Chairman</i> • <i>Director</i> • <i>Chair, Corporate Governance and Compensation Committee</i> • <i>Reserves Committee</i>	Director Since May 7, 2010 Mr. Brussa has been a partner of the Calgary based law firm of Burnet, Duckworth & Palmer LLP since 1987 and is presently the head of its Tax Department. Mr. Brussa is a Director of several public oil and gas companies.
David Fitzpatrick Alberta, Canada • <i>Director</i> • <i>Audit Committee</i> • <i>Corporate Governance and Compensation Committee</i> • <i>Reserves Committee</i>	Director Since May 7, 2010 Mr. Fitzpatrick is currently an independent businessman. From 1996 to 2007 Mr. Fitzpatrick was the President, Chief Executive Officer and Director of Shiningbank Energy Ltd.
David Johnson Alberta, Canada • <i>Director</i> • <i>Chairman, Reserves Committee</i> • <i>Audit Committee</i>	Director Since May 7, 2010 Mr. David D. Johnson is currently the Chairman of Progress Energy Resources Corp. (a public oil and gas company) which was formed in 2009. From 2004 to 2009, Mr. Johnson served as the Chairman of Progress Energy Trust. Mr. Johnson was the President and Chief Executive Officer of Pro-Ex from July 2004 to January 2009.
Rob Zakresky Alberta, Canada • <i>Director</i> • <i>Chairman, Audit Committee</i> • <i>Corporate Governance & Compensation Committee</i>	Director Since May 7, 2010 Mr. Zakresky has held the position of President and Chief Executive Officer of Crocotta Energy Inc. since November 2006.
Brent Gough Alberta, Canada • <i>Vice President, Operations</i>	Mr. Gough has been our Vice President, Operations since May 7, 2010. Prior thereto, Mr. Gough was the President of several private oil and gas companies as well as several private flow-through drilling funds. Prior to that, he was Vice President, Engineering at Edge Energy.
Joe Sobochan Alberta, Canada • <i>Vice President, Geology</i>	Mr. Sobochan has been our Vice President, Geology since October 6, 2010. Prior thereto, Mr. Sobochan held the positions of Senior Geologist with PetroBakken Energy Ltd. and Senior Geologist with Peerless Energy Inc.

**Name and Municipality of Residence
and Position**
**Principal Occupation
Past Five Years**
Dan Toews

Alberta, Canada

- *Vice President, Finance*
- *Chief Financial Officer*

Mr. Toews has been our Vice President, Finance & Chief Financial Officer since May 7, 2010. Prior thereto Mr. Toews was the Vice President Finance and Chief Financial Officer of Canadian Capital Energy Corporation (a private oil and gas company). Previously Mr. Toews held the position of Vice President Finance and Chief Financial Officer at Peerless Energy Inc.

Bill Turko

Alberta, Canada

- *Vice President Engineering*

Mr. Turko has been our Vice President, Engineering since May of 2010. Previously Mr. Turko was VP Engineering at Peerless Energy Inc. and prior to that he was the Chief Operating Officer of Enterra Energy Trust.

Jay Reid

Alberta, Canada

- *Corporate Secretary*

Mr. Reid is a partner at the Calgary based law firm of Burnet, Duckworth & Palmer LLP and has practiced corporate and securities law since 1990. Mr. Reid has been Corporate Secretary of the Company since May 7, 2010. He has served as director or officer of a number of publicly listed issuers and currently serves as a Director of Madalena Ventures Inc. and Renegade Petroleum Ltd. and as Corporate Secretary for TriOil Resources Ltd., Longview Oil Corp. and Advantage Oil and Gas Ltd. in addition to being a Director or Corporate Secretary for six private issuers.

Ownership of Shares

As at March 21, 2012 our directors and officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, 26,674,231 Common Shares or approximately 13.63% of our issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than set out below, to our knowledge, no director or officer: (i) is, or has been in the last 10 years, a director, Chief Executive Officer or Chief Financial Officer of an issuer that, while that person was acting in that capacity, (a) was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under securities legislation, for a period of more than 30 consecutive days (an "**order**"), (b) was subject to an order that was issued after the director or officer ceased to be a director, Chief Executive Officer or Chief Financial Officer and which resulted from an event that occurred while that person was acting in the capacity as director, Chief Executive Officer or Chief Financial Officer, or (c) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings,

arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; (ii) has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver or receiver manager or trustee appointed to hold his assets; or (iii) has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (b) any other penalties or sanctions imposed by a court or regulatory body.

Conflicts of Interest

There are potential conflicts of interest to which our directors and officers will be subject in connection with our operations. In particular, certain of our directors and officers are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with our operations or with entities which may, from time to time, provide financing to, or make equity investments in, our competitors. See "*Directors and Officers*". Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

DESCRIPTION OF SHARE CAPITAL

The following is a description of the rights, privileges, restrictions and conditions attaching to our share capital.

Common Shares

We are authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of Common Shares are entitled to one vote per share at meetings of Shareholders. Subject to the rights of the holders of preferred shares and any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors and upon liquidation, dissolution or winding up to receive, our remaining property. As of the date of this Annual Information Form, there are 195,636,364 Common Shares issued and outstanding.

Preferred Shares

We are authorized to issue an unlimited number of preferred shares without nominal or par value. There are currently no preferred shares issued and outstanding.

ESCROWED SECURITIES

The following securities are subject to contractual escrow restrictions pursuant to the terms of a voluntary escrow agreement among us, Olympia Trust Company, and certain security holders. The securities subject to voluntary escrow were issued as part of the private placement conducted in accordance with the Capitalization Agreement. See "*General Development of the Business – Year Ended July 31, 2010 – Capitalization Transaction*".

Class of Securities	Number of Securities Escrowed	Percentage of Class
Common Shares	7,357,138 ⁽¹⁾	3.76%
Purchase Warrants	8,564,638 ⁽¹⁾	25.36%

Note:

(1) The following securities are scheduled to be released from escrow as follows:

Date	Number of Common Shares	Number of Purchase Warrants
May 6, 2012	6,822,212	6,822,212
May 21, 2012	534,926	1,742,424

PRICE RANGE AND TRADING VOLUME OF THE COMMON SHARES

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

Period	High	Low	Volume
2011			
January	2.12	2.80	13,544,406
February	2.57	2.21	8,263,612
March	2.50	1.99	20,594,456
April	3.19	2.16	40,348,860
May	3.04	2.58	26,054,612
June	2.72	2.33	16,238,053
July	2.68	2.35	12,412,784
August	2.54	1.75	16,804,685
September	2.48	1.87	13,668,195
October	2.63	1.47	15,313,531
November	2.67	2.10	19,475,031
December	2.43	2.03	13,460,543
2012			
January	2.98	2.37	22,288,754
February	3.49	2.75	46,564,190
March (1 - 20)	3.34	2.92	22,663,901

DIVIDENDS

We have not declared or paid any dividends since our incorporation. Any decision to pay dividends on our shares will be made by the Board of Directors on the basis of our earnings, financial requirements and other conditions existing at such future time.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To our knowledge, there are no material legal proceedings to which we are a party, or were a party to in 2011, or that any of our properties is or was the subject matter of in 2011, nor are there any such proceedings known to us to be contemplated.

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than the interests described under the heading "*General Development of the Business – Year Ended December 31, 2010 – Capitalization Transaction*", there were no material interests, direct or indirect, of our directors, officers, or Shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Common Shares, or any other Informed Person (as defined in NI 51-102) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial that has materially affected or would materially affect us.

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The full text of our Audit Committee charter is included in Schedule C of this Annual Information Form.

Composition of the Audit Committee

The members of the Audit Committee are Robert Zakresky (Chairman), David Fitzpatrick and David Johnson each of whom are independent and financially literate. We have adopted the definition of "independence" as set out in Section 1.4 of National Instrument 52-110 – *Audit Committees*.

Relevant Education and Experience

Rob Zakresky, Director

Mr. Zakresky obtained his Bachelor of Commerce from the University of Saskatchewan in 1988. He obtained his Chartered Accountant designation with PricewaterhouseCoopers LLP in 1990. Mr. Zakresky has held the position of President and Chief Executive Officer of Crocotta Energy Inc. since November 2006. See "*Directors and Officers*" for further information on Mr. Zakresky's experience.

David Fitzpatrick, Director

Mr. Fitzpatrick obtained his Geologic Engineering Degree from Queen's University in 1981. He obtained his Executive Management Program Certificate from Queen's University in 1994 and his Chartered Directors Program Certificate from DeGroote School of Business, McMaster University in 2008. Mr. Fitzpatrick is a member of the Society of Petroleum Engineers, the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and has a Chartered Director designation. See "*Directors and Officers*" for further information on Mr. Fitzpatrick's experience.

David D. Johnson, Director

Mr. Johnson has over 30 years of diverse experience in the oil and gas industry including a background in production, reservoir evaluation and operations. He has a B.Sc. in Petroleum Engineering, is a member of the Association of Engineers, Geologists and Geophysics of Alberta and has served twice as a governor of the Canadian Association of Petroleum Producers. See "*Directors and Officers*" for further information on Mr. Johnson's experience.

Pre-Approval of Policies and Procedures

The Audit Committee must pre-approve all non-audit services to be provided to us by our external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by the Audit Committee from time to time.

External Auditor Service Fees

Audit Fees

PricewaterhouseCoopers LLP are our auditors. PricewaterhouseCoopers LLP have been our auditors since November 2010. Prior to the completion of the Capitalization Transaction and the change of our year end, our auditors were Buchanan Barry LLP. See "*General Development of the Business*".

Fees we incurred with PricewaterhouseCoopers LLP for audit and non-audit services in the last two fiscal years are outlined in the following table.

Nature of Services	Year ended December 31, 2011	Five months ended December 31, 2010
Audit Fees ⁽¹⁾	\$ 121,000	\$ 44,100
Audit-Related Fees ⁽²⁾	67,200	89,775
Tax Fees ⁽³⁾	10,500	11,800
All Other Fees ⁽⁴⁾	-	-
Total	\$ 198,700	\$ 145,675

Notes:

- (1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of our financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.
- (2) "Audit-Related Fees" for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and are not reported as audit fees. The services provided in this category include due diligence assistance, accounting consultations on proposed transactions, and consultation on International Financial Reporting Standards ("IFRS") conversion.
- (3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice.
- (4) "All Other Fees" include all other non-audit services.

Fees incurred with Buchanan Barry LLP for audit and non-audit services for the year ended July 31, 2010 are outlined in the following table.

Nature of Services	Year Ended July 31, 2010 ⁽⁵⁾
Audit Fees ⁽¹⁾	\$ 41,500
Audit-Related Fees ⁽²⁾	70,000
Tax Fees ⁽³⁾	7,700
All Other Fees ⁽⁴⁾	-
Total	\$ 119,200

Notes:

- (1) "Audit Fees" include fees necessary to perform the annual audit and quarterly reviews of our financial statements. Audit Fees include fees for review of tax provisions and for accounting consultations on matters reflected in the financial statements. Audit Fees also include audit or other attest services required by legislation or regulation, such as comfort letters, consents, reviews of securities filings and statutory audits.
- (2) "Audit-Related Fees" include services that are traditionally performed by the auditor. These audit-related services include employee benefit audits, due diligence assistance, accounting consultations on proposed transactions, internal control reviews and audit or attest services not required by legislation or regulation.
- (3) "Tax Fees" include fees for all tax services other than those included in "Audit Fees" and "Audit-Related Fees". This category includes fees for tax compliance, tax planning and tax advice. Tax planning and tax advice includes assistance with tax audits and appeals, tax advice related to mergers and acquisitions, and requests for rulings or technical advice from tax authorities.
- (4) "All Other Fees" include all other non-audit services.
- (5) Our fiscal year end was July 31 until it was changed to December 31 on November 25, 2010.

Reliance on Exemptions

Other than reliance of section 6.1 of National Instrument 52-110 – *Audit Committees* as a venture issuer, at no time since the commencement of our most recently completed financial year have we relied on any of the exemptions contained in National Instrument 52-110 – *Audit Committees* with respect to independence or composition of its Audit Committee.

Audit Committee Oversight

At no time since the commencement most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by our Board of Directors.

MATERIAL CONTRACTS

We have not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect.

INDUSTRY CONDITIONS

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

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. 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, 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.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 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.

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

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a

minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

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

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

Alberta

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

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/m³ 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.

Saskatchewan

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

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of \$100 per m³ for third and fourth tier oil and \$50 per m³ for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (having a finished

drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m³ of gas for every m³ of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* replacing the existing *Freehold Oil and Gas Production Tax Act* with the intention to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new legislation, although several regulations remain in force under the previous legislation.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of \$50 per thousand m³ for third and fourth tier gas and \$35 per thousand m³ for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas.

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

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m³ for deep development vertical oil wells, 4,000 m³ for non-deep exploratory vertical oil wells and 16,000 m³ for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);
- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m³ for qualifying exploratory gas wells;
- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m³ for non-deep horizontal oil wells and 16,000 m³ for deep horizontal oil wells (more than 1,700 metres or within certain formations);
- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m³ for horizontal gas wells;
- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005* providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production

tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout; and

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

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

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

Land Tenure

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

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences 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.

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 CO₂ equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO₂ equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors 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 CO₂ 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 CO₂ 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.

Saskatchewan

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

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation 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 and British Columbia 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 interests held in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Dividends

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

Aboriginal Claims

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

Seasonality

The level of activity in the Canadian oil and 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, REGISTRAR AND TRANSFER AGENT

Our auditors are PricewaterhouseCoopers LLP, Chartered Accountants, Suite 3100, 111 – 5th Avenue SW, Calgary, Alberta, T2P 5L3.

Olympia Trust Company, at its principal offices in Calgary, Alberta, is the registrar and transfer agent for the Common Shares.

INTEREST 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 NI 51-102 by us during, or related to, our most recently completed financial year other than Sproule, the independent reserve evaluator, and PricewaterhouseCoopers LLP, our auditors. None of the principals of Sproule had any registered or beneficial interests, direct or indirect, in any of our securities or other property or securities or other property of our 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 is independent in accordance with the auditors' 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 one of our directors, officers or employees or as a director, officer or employee of any of our associates or affiliates except for John Brussa, Chairman of our Board and Jay Reid, our Corporate Secretary, both of whom are partners at Burnet, Duckworth & Palmer LLP, a law firm which renders legal services to us.

ADDITIONAL INFORMATION

Additional information can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, is contained in our information circular for the most recent annual meeting of Shareholders that involved the election of directors. Additional financial information is provided for in our financial statements and management's discussion and analysis for the year ended December 31, 2011.

SCHEDULE "A"

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

Management of Pinecrest Energy Inc. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

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

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

- (a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;
- (b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and
- (c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

- (d) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;
- (e) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and
- (f) the content and filing of this report.

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

DATED as of this 21st day of March, 2012.

(signed) "*Wade Becker*"
Wade Becker
President and Chief Executive Officer

(signed) "*Bill Turko*"
Bill Turko
Vice-President, Engineering

(signed) "*John Brussa*"
John Brussa
Director

(signed) "*David Johnson*"
David Johnson
Director

Form 51-101F2

Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of Pinecrest 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.

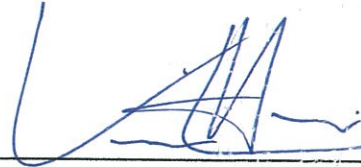
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us 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 or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M\$)	Evaluated (M\$)	Reviewed (M\$)	Total (M\$)
Sproule	Evaluation of the P&NG Reserves of Pinecrest Energy Inc., As of December 31, 2011, prepared December 2011 to March 2012	Canada				
Total			Nil	239,769	Nil	239,769

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
March 19, 2012

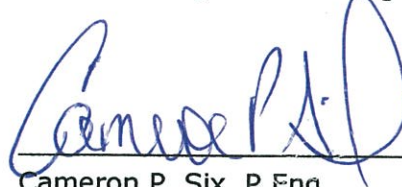


Vincent K. Hui, P.Eng.
Petroleum Engineer



for

Brian G. Trieber, P.L. (Geol.)
Senior Geological Technologist and Partner



Cameron P. Six, P.Eng.
Vice-President, Engineering and Partner

SCHEDULE "C"

PINECREST ENERGY INC.

AUDIT COMMITTEE CHARTER AND POSITION DESCRIPTION FOR AUDIT COMMITTEE CHAIR

Introduction

Pinecrest Energy Inc. (the "Corporation") is an Alberta based junior oil and gas exploration and development company. The Board of Directors of the Corporation (the "Board") has the responsibility for the overall stewardship of the conduct of the business of the Corporation and its subsidiaries and the activities of management of the Corporation, which is responsible for the day-to-day conduct of the business.

Purpose

The primary function of the Audit Committee (the "Committee") is to assist the Board in fulfilling its responsibilities by reviewing: the financial reports and other financial information provided by the Corporation to any governmental body or the public; the Corporation's systems of internal controls regarding finance, accounting, legal compliance and ethics that management and the Board have established; and the Corporation's auditing, accounting and financial reporting processes generally. Consistent with this function, the Committee should endeavour to encourage continuous improvement of, and should endeavour to foster adherence to, the Corporation's policies, procedures and practices at all levels. In performing its duties, the external auditor is to report directly to the Committee. The Committee's primary objectives are:

- (1) To assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;
- (2) To provide better communication between directors and external auditors;
- (3) To assist the Board's oversight of the auditor's qualifications and independence;
- (4) To assist the Board's oversight of the credibility, integrity and objectivity of financial reports;
- (5) To strengthen the role of the outside directors by facilitating discussions between directors on the Committee, management and external auditors;
- (6) To assist the Board's oversight of the performance of Corporation's internal audit function and external auditors; and
- (7) To assist the Board's oversight of the Corporation's compliance with legal and regulatory requirements.

Composition, Procedures and Organization

- (1) The Committee shall consist of at least three members of the Board of Directors (the "Board"), a majority of whom shall be "independent", as that term is defined in Sections 1.4 and 1.5 of Multilateral Instrument 52-110, *Audit Committees* ("MI 52-110") (provided that, if the Common Shares of the Corporation are listed and posted on the Toronto Stock Exchange, then all of the members of the Audit Committee shall be "independent").
- (2) All of the members of the Committee shall be "financially literate" (i.e. able to read and understand a set of financial statements that present a breadth and level of complexity of

accounting issues that are generally comparable to the breadth and complexity of those of the Corporation and that can be reasonably expected to be raised by the Corporation's financial statements).

- (3) The Committee composition, including the qualifications of its members, shall comply with the applicable requirements of stock exchanges on which the Corporation lists its securities and of securities regulatory authorities, as such requirements may be amended from time to time.
- (4) The Board shall appoint the members of the Committee. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.
- (5) Unless the Board shall have appointed a chair of the Committee, the members of the Committee shall elect a chair from among their members.
- (6) The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.
- (7) The Committee shall have access to such officers and employees of the Corporation and to the Corporation's external auditors, and to such information respecting the Corporation, as it considers necessary or advisable in order to perform its duties and responsibilities.
- (8) Meetings of the Committee shall be conducted as follows:
 - (a) the Committee shall meet at least four times annually at such times and at such locations as may be requested by the chair of the Committee. The external auditors or any member of the Committee may request a meeting of the Committee;
 - (b) the external auditors may receive notice of and have the opportunity to attend meetings of the Committee; and
 - (c) the following management representatives may be invited to attend meetings, except executive sessions and private sessions with the external auditors:

President and Chief Executive Officer
Chief Financial Officer
Controller

other management representatives may be invited to attend as necessary.

- (9) The external auditors shall report directly to the Committee and the external auditors and internal auditors (if any) shall have a direct line of communication to the Committee through its chair and may bypass management if deemed necessary. The Committee, through its chair, may contact directly any employee of the Corporation as it deems necessary, and any employee may bring before the Committee any matter involving questionable, illegal or improper financial practices or transactions.
- (10) The Committee may retain, at the Corporation's expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties and may set and pay the compensation for any advisor engaged. The Committee will notify the Board Chair whenever independent consultants are engaged.

Handling of Complaints

The Committee shall maintain procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters, and the

confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters (a "Whistleblower Policy").

Annual Review

The Committee shall review and assess the adequacy of this Charter annually, report to the Board thereon and recommend any proposed changes to the Board for approval. The Committee shall also perform an annual evaluation of the performance of the Committee and shall report the results of the evaluation to the Board Chair.

Roles and Responsibilities

- (1) The overall duties and responsibilities of the Committee shall be as follows:
 - (a) to assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and its approval of the Corporation's annual and quarterly financial statements and management's discussion and analysis;
 - (b) to establish and maintain a direct line of communication with the Corporation's internal (if any) and external auditors and assess their performance;
 - (c) to assist the Board in the discharge of its responsibilities relating to oversight of the Company's internal, financial and disclosure controls and procedures;
 - (d) to pre-approve all non-audit services to be provided by the Corporation's external auditor and to periodically review the audit and non-audit services pre-approval policy and recommend to the Board any changes which the Committee deems appropriate. The Committee may delegate to one or more members of the Committee authority to pre-approve non audit services in satisfaction of this requirement and if such delegation occurs, the pre-approval of non-audit services by the Committee member to whom authority has been delegated must be presented to the Committee at its first scheduled meeting following such pre-approval. The Committee shall be entitled to adopt specific policies and procedures for the engagement of non-audit services if:
 - (i) the pre-approval policies and procedures are detailed as to the particular service;
 - (ii) the Committee is informed of each non-audit service; and
 - (iii) the procedures do not include delegation of the Committee's responsibilities to management.

The Committee will satisfy the pre-approval requirement set forth above if:

- (i) the aggregate amount of all non-audit services that were not pre-approved is reasonably expected to constitute no more than 5% of the total amount of fees paid by the Corporation and its subsidiary entities to the external auditors during the fiscal year in which the services are provided;
- (ii) the Corporation or the subsidiary entity, as the case may be, did not recognize the services as non-audit services at the time of the engagement;
- (iii) the services are promptly brought to the attention of the Committee and approved, prior to completion of the audit, by the Committee or by one or more of

its members to whom authority to grant such approvals has been delegated by the Committee;

- (e) to periodically consider whether there is a need to outsource internal audit functions or create an internal audit department;
 - (f) to review the reports to management prepared by the external auditors and management's responses;
 - (g) to receive and review complaints received pursuant to the Corporation's Whistleblower Policy and oversee and provide direction on the investigation and resolution of such concerns and to periodically review the said policy and recommend to the Board changes which the Committee may deem appropriate;
 - (h) to report regularly to the Board on the fulfilment of its duties and responsibilities;
 - (i) to review significant findings during the year, including the status of previous significant audit recommendations;
 - (j) to identify and monitor the management of the principal risks that could impact the financial reporting of the Corporation;
 - (k) to ensure that it satisfies those responsibilities set out in Part 2 of MI 52-110 and provisions contained within the Companion Policy to MI 52-110; and
 - (l) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation.
- (2) The duties and responsibilities of the Committee as they relate to the external auditors shall be as follows:
- (a) to be directly responsible for overseeing the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the external auditors regarding financial reporting;
 - (b) to recommend to the Board a firm of external auditors to be nominated for appointment by the shareholders of the Corporation, and to monitor and verify the independence of such external auditors;
 - (c) to review and approve the fee, scope and timing of the audit and other audit related and non-audit services rendered by the external auditors;
 - (d) review the audit plan of the external auditors prior to the commencement of the audit;
 - (e) to review with the external auditors, upon completion of their audit:
 - (i) contents of their report;
 - (ii) scope and quality of the audit work performed;
 - (iii) adequacy of the Corporation's financial and auditing personnel;
 - (iv) co-operation received from the Corporation's personnel during the audit;

- (v) internal resources used;
 - (vi) significant transactions outside of the normal business of the Corporation;
 - (vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems; and
 - (viii) the non-audit services provided by the external auditors, as pre-approved pursuant to the audit and non-audit services pre-approval policy;
 - (f) to discuss with the external auditors the quality and not just the acceptability of the Corporation's accounting principles;
 - (g) when there is to be a change in external auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;
 - (h) to review any unresolved issues between management and the external auditors that could affect the financial reporting or internal controls of the Corporation;
 - (i) to implement structures and procedures to ensure that the Committee meets the external auditors on a regular basis in the absence of management; and
 - (j) to receive a written statement from the external auditor describing in detail all relationships between the auditor and the Corporation that may impact the objectivity and independence of the auditor. The Committee shall review with the Board of Directors the independence of the external auditors and either confirms to the Board of Directors that the external auditors are independent or recommend that the Board of Directors take appropriate action to satisfy itself of the external auditor's independence.
- (3) The duties and responsibilities of the Committee as they relate to the internal control procedures of the Corporation are to:
- (a) review the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to insurance, accounting, information services and systems and financial controls, management reporting and risk management;
 - (b) review compliance under the Corporation's Code of Business Conduct with those matters addressed in the policy which affect the financial integrity of the Corporation and to periodically review this policy, management's monitoring of it, and recommend to the Board changes which the Committee may deem appropriate; and
 - (c) periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the internal accounting staff or by the external auditors have been implemented.
- (4) The Committee is also charged with the responsibility to:
- (a) review and recommend to the Board for its approval, the Corporation's financial statements, management's discussion and analysis and annual and interim earnings press releases before the Corporation publicly discloses this information;
 - (b) review and approve the Corporation's interim financial statements, interim management's discussion and analysis including the impact of unusual items and changes in accounting

principles and estimates and report to the Board with respect thereto and interim earnings press releases before the Corporation publicly discloses this information;

- (c) review the financial sections of:
 - (i) the annual report to shareholders;
 - (ii) prospectuses;
 - (iii) other public reports containing financial information requiring approval by the Board; and
 - (iv) press releases related thereto,

and report to the Board with respect thereto;

- (d) review regulatory filings and decisions as they relate to the Corporation's financial statements;
- (e) review the appropriateness of any policies and procedures used in the preparation of the Corporation's financial statements and other required disclosure documents, and consider recommendations for any material change to such policies;
- (f) review and report on the integrity of the Corporation's financial statements;
- (g) review the minutes of any audit committee meeting of any subsidiary of the Corporation;
- (h) review with management, the external auditors and, if necessary, with legal counsel, any litigation, claim or other contingency, including tax assessments that could have a material effect upon the financial position or operating results of the Corporation and the manner in which such matters have been disclosed in the consolidated financial statements;
- (i) review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements, tax matters and disclosure of material facts;
- (j) endeavour to ensure all material public documents relating to the financial performance, financial position or analysis thereon are reviewed by the Committee or another appropriate committee, as designated by the Board of Directors. In certain cases, including in respect of "roadshow" or other investor materials, the Committee may designate the responsibility for review to the Chair of the Committee, the Chief Financial Officer of the Corporation or to legal counsel. The Committee shall review and monitor practices and procedures adopted by the Corporation to assure compliance with applicable listing requirements, laws, regulations and other rules, and where appropriate, make recommendations or reports thereon to the Board of Directors;
- (k) The Committee shall review significant changes in the accounting principles to be observed in the preparation of the accounts of the Corporation and its subsidiaries, or in their application, and in financial disclosure presentation; and
- (l) The Committee shall review such reports as may be required by any applicable securities regulatory authority to be included in the Corporation's Information Circular or any other disclosure document of the Corporation.

Accountability

The Committee shall report its activities and proceedings to the Board by distributing the minutes of its meetings or by oral or written report at the next Board meeting.

Standards of Liability

Nothing contained in this mandate is intended to expand applicable standards of liability under statutory, regulatory, common law or any other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this mandate are meant to serve as guidelines rather than inflexible rules and the Committee may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.

Annual Review and Assessment

The Committee shall conduct an annual review and assessment of its performance, including compliance with this Charter and its role, duties and responsibilities, and submit such report to the Board of Directors. The Committee shall also update this Charter periodically as conditions dictate.