



ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2009

March 12, 2010

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ABBREVIATIONS

Oil and Natural Gas Liquids

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

Natural Gas

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

Other

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

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

CONVERSIONS

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

CERTAIN DEFINITIONS

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

"2005 Arrangement" means the plan of arrangement involving the Trust, Fairborne, Fairborne ExchangeCo Ltd. and Fairquest completed on June 1, 2005 under the ABCA pursuant to which, among other things, the Trust indirectly acquired all of the issued and outstanding Common Shares of Fairborne;

"2007 Reorganization" means the plan of arrangement involving the Trust, Fairborne, certain subsidiaries of the Trust and securityholders of the Trust completed on December 19, 2007 under the ABCA, pursuant to which Fairborne, directly or indirectly, acquired all of the assets and assumed all of the liabilities, respectively of the Trust;

"2007 Reorganization Arrangement Agreement" means the arrangement agreement dated as of November 13, 2007 among the Trust, Fairborne and Fairborne Newco Inc. in respect of the 2007 Reorganization;

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

"Business Day" means a day other than a Saturday, Sunday or statutory holiday, when banks are generally open for business in the city of Calgary, in the province of Alberta, for the transaction of banking business.

"CBM" means coal bed methane;

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

"Common Shares" means the Common Shares in the capital of Fairborne;

"Debentures" means the 6.50% convertible unsecured subordinated debentures of Fairborne issued pursuant to the Debenture Indenture;

"Debenture Indenture" means the trust indenture dated October 31, 2006, as amended and restated as of December 19, 2007 among Fairborne and the Debenture Trustee governing the terms of the Debentures;

"Debenture Trustee" means Computershare Trust Company of Canada or its successor as trustee under the Debenture Indenture;

"Denham" means Denham Commodity Partners Fund IV LP;

"Fairborne " or the **"Corporation"** means Fairborne Energy Ltd., a corporation amalgamated pursuant to the 2007 Reorganization and includes its predecessors where the context so requires;

"GLJ" means GLJ Petroleum Consultants Ltd.;

"GLJ Report" means the report of GLJ dated February 12, 2010 evaluating our crude oil, natural gas liquids and natural gas reserves as at December 31, 2009;

"Grand Banks" means Grand Banks Energy Corporation, a corporation continued pursuant to the ABCA;

"Gross" means:

- (a) in relation to our interest in production and reserves, our "company gross reserves", which are our interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;
- (b) in relation to wells, the total number of wells in which we have an interest; and
- (c) in relation to properties, the total area of properties in which we have an interest.

"Incentive Plan" means the restricted unit and performance unit incentive plan of Fairborne, as successor to the Trust;

"Income Tax Act" or **"Tax Act"** means the *Income Tax Act* (Canada), R.S.C. 1985, c. 1. (5th Supp), as amended, including the regulations promulgated thereunder;

"Net" means:

- (a) in relation to our interest in production and reserves, our working interest (operating and non-operating) share after deduction of royalties obligations, plus our royalty interest in production or reserves;
- (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
- (c) in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest we own.

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

"Non-Vesting Participants" means all of the members of the board of directors and the Chief Executive Officer, Chief Financial Officer and Chief Operating Officer of Fairborne;

"Performance Units" means performance units issued pursuant to the Incentive Plan;

"Restricted Units" means restricted units issued pursuant to the Incentive Plan;

"Subsidiaries" means, with respect to any Person, a subsidiary (as that term is defined in the ABCA (for such purposes, if such person is not a corporation, as if such person were a corporation)) of such Person and includes any limited partnership, joint venture, trust, limited liability company, unlimited liability company or other entity, whether or not having legal status, that would constitute a subsidiary (as described above) if such entity were a corporation;

"Trust" means Fairborne Energy Trust, a trust established under the laws of Alberta;

"Trust Units" means the previously outstanding trust units of the Trust as they existed prior to completion of the 2007 Reorganization;

"Trust Unitholders" or **"Unitholders"** means the former holders of Trust Units; and

"TSX" means the Toronto Stock 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 the Corporation's most recently completed financial year, being December 31, 2009.

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

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, drilling, testing, tie-in and re-completion plans and timing, productive capacity of wells and productive capacity of wells and capital expenditures, the timing and financing thereof and nature of expenditures; the effect of government announcements, proposals and legislation, plans regarding hedging, expected or anticipated production rates, timing of expected production increases, weighting of production between different commodities, expected commodity prices, exchange rates, production expenses, transportations costs and other costs and expenses and plans and timing of the Clive CO2 project may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Fairborne's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Fairborne believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because Fairborne 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 Fairborne operates; the timely receipt of any required regulatory approvals; the ability of Fairborne 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 Fairborne has an interest in to operate the field in a safe, efficient and effective manner; the ability of Fairborne to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Fairborne 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 Fairborne operates; and the ability of Fairborne to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could effect Fairborne's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), at Fairborne's website (www.fairborne-energy.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 Fairborne assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

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

BACKGROUND

General

Fairborne is an Alberta based growth oriented, intermediate oil and gas company engaged in the exploration for, and the acquisition, development and production of, oil and natural gas reserves primarily in western Canada.

Fairborne was amalgamated pursuant to the provisions of the ABCA on December 19, 2007 pursuant to the 2007 Reorganization.

Fairborne's head office is located at 3400, 450 - 1st Street SW, Calgary, AB T2P 5H1 and its registered office is located at 1400, 350 – 7th Ave. SW, Calgary, Alberta T2P 3N9.

Fairborne's Common Shares and Debentures trade on the TSX under the symbols "FEL" and "FEL.DB", respectively.

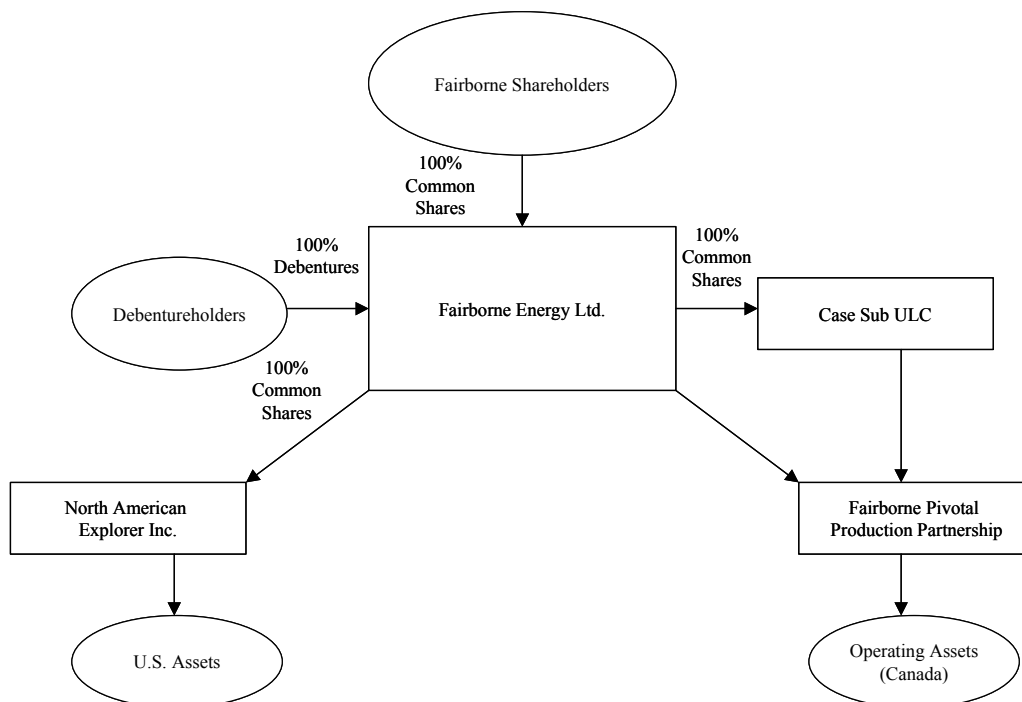
Inter-Corporate Relationships

The following are the names, the percentage of voting securities that we own and the jurisdiction of incorporation, continuance or formation of our material Subsidiaries, direct and indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	Nature of Entity	Jurisdiction of Incorporation/ Formation
Fairborne Energy Ltd	100%	Corporation	Alberta
Case Sub ULC	100%	Corporation	Alberta
North American Explorer Inc.	100%	Corporation	Wyoming
Fairborne Pivotal Production Partnership	100%	General Partnership	Alberta

Our Organization Structure

The following diagram describes the inter-corporate relationships among Fairborne and its material Subsidiaries.



GENERAL DEVELOPMENT OF OUR BUSINESS

History of Fairborne Energy Ltd.

Fairborne has been engaged in the business of acquiring crude oil and natural gas properties and exploring for, developing and producing crude oil and natural gas in Western Canada since it began operations in May of 2002. Fairborne became a publicly traded corporation in July, 2003 upon completion of its acquisition of Pivotal Energy Ltd. Fairborne has executed its growth strategy through exploration and development programs combined with both corporate and property acquisitions. Financing for these programs has been obtained through a combination of cash flow from operations, various equity issues of common shares and common shares issued on a "flow through" basis and bank credit facilities.

The 2005 Arrangement – Transformation to a Trust

On June 1, 2005 the 2005 Arrangement was completed which resulted in the creation of Fairborne Energy Trust, a new oil and natural gas energy trust that acquired approximately 90% of Fairborne's then existing producing assets and the creation of Fairquest Energy Limited ("**Fairquest**"), a junior oil and natural gas exploration and development company which acquired the balance of Fairborne's oil and natural gas assets and certain undeveloped lands.

Under the 2005 Arrangement, shareholders of Fairborne received, at their election, either one Trust Unit or one exchangeable share of Fairborne ("**Exchangeable Shares**") and 0.333 of a common share of Fairquest, for each outstanding common share of Fairborne held. Immediately following completion of the 2005 Arrangement, approximately 45 million Trust Units and seven million Exchangeable Shares were outstanding.

Public Offering of 6.50% Convertible Unsecured Subordinated Debentures

On October 31, 2006 the Trust completed a public offering of Debentures by way of short form prospectus at a price of \$1,000 per Debenture for aggregate gross proceeds of \$100 million. The Debentures trade on the TSX under the symbol "FEL-DB". The Debentures have a maturity date of December 31, 2011 and bear interest at an annual rate of 6.50%, payable semi-annually on December 31 and June 30 in each year. The Debentures were assumed by Fairborne in connection with the 2007 Reorganization and, as such, are now convertible at the option of the holder into Common Shares at a price of \$13.50 per Common Share and are redeemable by Fairborne in certain circumstances. See "*Borrowings – Debentures*".

Acquisition of Fairquest Energy Limited

On June 4, 2007 the Trust, through Fairborne, completed the acquisition of all of the outstanding shares of Fairquest pursuant to a plan of arrangement under the ABCA (the "**Fairquest Arrangement**"). Prior to completion of the Fairquest Arrangement, Fairquest was a reporting issuer in certain provinces of Canada and its Common Shares were listed for trading on the TSX under the symbol "FQE". Pursuant to the terms of the Fairquest Arrangement, shareholders of Fairquest received, for each outstanding share held by them, 0.39 of a Trust Unit. Fairborne also assumed approximately \$48 million of net debt upon closing of the Fairquest Arrangement. Following completion of the Fairquest Arrangement, the common shares of Fairquest were de-listed from trading on the TSX and Fairquest ceased to be a reporting issuer.

Fairquest was a junior exploration and production company with operations in Alberta. At the time of the Fairquest Arrangement, Fairquest's production was approximately 2,800 boe/d (84% natural gas). The assets of Fairquest also included approximately 68,000 acres (107 net sections) of undeveloped land.

Following the Fairquest Arrangement all of the producing petroleum and natural gas properties and related interests of Fairquest were contributed to the Fairborne Pivotal Production Partnership. Fairquest was dissolved under the provisions of the ABCA on February 14, 2008.

The 2007 Reorganization – Transformation to a Corporation and \$100 Million Private Placement

On December 19, 2007 Fairborne completed a plan of arrangement under the ABCA involving Fairborne, the Trust, certain subsidiaries of the Trust and securityholders of the Trust, pursuant to which Fairborne, directly or indirectly, acquired all of the assets and assumed all of the liabilities, respectively, of the Trust. Prior to completion of the 2007 Reorganization, the Trust was a reporting issuer in certain provinces of Canada and the Trust Units and the

Exchangeable Shares were listed for trading on the TSX. Following completion of the 2007 Reorganization, the Trust Units and Exchangeable Shares were de-listed from trading on the TSX and the Trust ceased to be a reporting issuer.

Pursuant to the 2007 Reorganization, previous holders of Trust Units received one Common Share for each one Trust Unit held and previous holders of Exchangeable Shares received Common Shares based on the exchange ratio for the Exchangeable Shares in effect on completion of the 2007 Reorganization. The former securityholders of the Trust received in the aggregate 70,859,581 Common Shares in exchange for all the outstanding Trust Units and Exchangeable Shares.

In connection with the completion of the 2007 Reorganization, Fairborne assumed all of the covenants and obligations of the Trust under the outstanding Debentures which are now convertible into Common Shares, rather than Trust Units, at the same conversion price that previously existed for the Trust Units, being a conversion price of \$13.50 per Common Share, subject to adjustment as provided in the Debentures.

Immediately following and in connection with completion of the 2007 Reorganization, Fairborne completed the issuance, on a private placement basis, of approximately 13.4 million Common Shares to Denham, a U.S. based private equity fund advised by Denham Capital Management LP, at a subscription price of \$7.45 per share, for aggregate proceeds of approximately \$100 million. Proceeds of the private placement were used to reduce outstanding indebtedness.

Post 2007 Reorganization

Following the 2007 Reorganization, Fairborne has continued to focus on enhancing its asset base through exploratory and development drilling within its core project areas and the completion of strategic acquisitions. Funding for Fairborne's growth has come from a combination of cash flow from ongoing operations, the Corporation's bank facility and equity financings undertaken from time to time as noted below.

2008 Private Placement Financing

On May 28, 2008 Fairborne completed a private placement of 2,000,000 Common Shares, issued on a "flow-through" basis, at an issue price of \$12.35 per share for gross proceeds of \$24.7 million.

Acquisition of Grand Banks Energy Corporation

On June 12, 2008 Fairborne acquired over 93% of the issued and outstanding shares of Grand Banks pursuant to an offer to purchase on the basis of \$2.90 in cash per share of Grand Banks (the "**Grand Banks Acquisition**"). Fairborne acquired the balance of the issued and outstanding shares of Grand Banks pursuant to the compulsory acquisition provisions under the ABCA effective June 16, 2008. The previous shareholders of Grand Banks received a total of \$101.7 million in cash in exchange for all of the outstanding shares of Grand Banks. Fairborne also assumed \$10.7 million of Grand Banks' net debt upon closing of the Grand Banks Acquisition. Prior to the Grand Banks Acquisition, the shares of Grand Banks were listed on the TSX Venture Exchange and Grand Banks was a reporting issuer in certain provinces of Canada.

Following completion of the Grand Banks Acquisition, the shares of Grand Banks were delisted from trading on the TSX Venture Exchange and Grand Banks ceased to be a reporting issuer.

Grand Banks was a junior exploration and production company with operations focussed in southeast Saskatchewan, southwest Manitoba and west central Alberta. At the time of completion of the Grand Banks Acquisition, Grand Banks' production was approximately 1,500 boe/d (approximately 50% oil and 50% natural gas). The assets of Grand Banks also included approximately 37,700 net acres of undeveloped land.

Following the Grand Banks Acquisition, all of the producing petroleum and natural gas properties and related interests of Grand Banks were contributed into the Fairborne Pivotal Production Partnership. Grand Banks was formally dissolved under the ABCA on December 4, 2009.

2009 Short Form Prospectus Offering

On October 7, 2009 Fairborne completed a short form prospectus offering of 11,649,000 Common Shares at an issue price of \$4.25 per share and 3,780,000 Common Shares, issued on a "flow-through" basis, at an issue price of \$5.30 per share, for aggregate gross proceeds of \$69.5 million.

SIGNIFICANT ACQUISITIONS

Fairborne has not completed any significant acquisitions during its most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102.

DESCRIPTION OF THE BUSINESS AND OPERATIONS

Business Plans and Growth Strategies

The business plan of Fairborne is to create sustainable and profitable per share growth in reserves, production and cash flow in the oil and gas industry in Western Canada. To accomplish this, Fairborne has pursued and will continue to pursue an integrated growth strategy with active development and exploration drilling, together with focused acquisitions. Fairborne will continue to target areas and prospects that it believes could result in meaningful reserve and production additions.

Fairborne will continue to pursue internal and external generation of exploration plays that have low to medium risk and multi-zone potential. Fairborne intends to maintain a balance between exploration, exploitation and development drilling largely targeting natural gas reserves over the course of the next several years. Management of Fairborne considers asset and corporate acquisition opportunities from time to time that meet Fairborne's business parameters.

Management of Fairborne has industry experience in producing areas in western Canada in addition to its current geographic areas of interest and has the capability to expand the scope of Fairborne's activities as opportunities arise.

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

- the company's technical expertise in the opportunity;
- the amount of risk capital required to secure or evaluate the investment opportunity;
- the potential return on the project, if successful;
- the likelihood of success; and
- risked return versus cost of capital.

In general, Fairborne intends to continue its pursuit of a portfolio approach in developing a large number of opportunities with a balance of risk profiles and commodity exposure in an attempt to generate sustainable high levels of growth.

Fairborne may pursue asset or corporate acquisitions or investments that do not conform to the guidelines discussed above based upon its consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality.

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

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Fairborne competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Fairborne's competitors include resource companies which have greater financial resources, staff and facilities than those of Fairborne. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Fairborne believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 12, 2010. The effective date of the Statement is December 31, 2009 and the preparation date of the Statement is January 28, 2010.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by GLJ with an effective date of December 31, 2009 contained in the GLJ 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 GLJ Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101. We engaged GLJ 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, Manitoba and Saskatchewan.

The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by our independent qualified reserves evaluator in Form 51-101F2 are attached as Schedule "A" and Schedule "B" respectively, hereto.

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

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES AND NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2009 FORECAST PRICES AND COSTS

RESERVES CATEGORY	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		CONVENTIONAL NATURAL GAS		COAL BED METHANE		NATURAL GAS LIQUIDS	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
PROVED										
Developed Producing	4,380	3,636	35	32	76,923	65,709	24,861	22,504	2,653	1,742
Developed Non-Producing	491	375	121	107	7,248	6,383	1,879	1,666	356	244
Undeveloped	1,345	1,187	128	130	51,302	46,416	7,130	6,300	2,425	1,700
TOTAL PROVED	6,216	5,197	285	268	135,473	118,508	33,870	30,470	5,433	3,686
PROBABLE	3,738	3,069	228	205	83,028	71,611	9,819	8,774	3,636	2,383
TOTAL PROVED PLUS PROBABLE	9,954	8,267	512	473	218,501	190,119	43,689	39,244	9,069	6,069

NET PRESENT VALUES OF FUTURE NET REVENUE

RESERVES CATEGORY	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
	0	5	10	15	20	0	5	10	15	20
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
PROVED										
Developed Producing	810,239	624,840	510,969	434,543	379,847	732,218	573,479	474,988	408,135	359,760
Developed Non-Producing	83,157	62,278	49,069	40,094	33,657	60,160	44,715	35,042	28,538	23,921
Undeveloped	391,107	252,705	171,641	120,508	86,351	295,470	187,998	124,864	84,996	58,380
TOTAL PROVED	1,284,502	939,822	731,679	595,144	499,855	1,087,849	806,192	634,895	521,669	442,062
PROBABLE	877,625	499,273	317,834	218,108	157,707	658,371	370,911	233,029	157,309	111,568
TOTAL PROVED PLUS PROBABLE	2,162,127	1,439,096	1,049,513	813,252	657,562	1,746,220	1,177,103	867,924	678,978	553,630

**TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS
(\$000s)**

RESERVES CATEGORY	REVENUE	ROYALTIES	OPERATING COSTS	DEVELOPMENT COSTS	ABANDONMENT AND RECLAMATION COSTS	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
Proved Reserves	2,375,672	367,505	508,665	193,773	21,227	1,284,502	196,653	1,087,849
Proved Plus Probable Reserves	3,968,749	642,366	811,208	327,085	25,962	2,162,127	415,907	1,746,220

**FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS**

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/year) (\$000s)	Unit Value Before Income Tax Discounted at 10%/year (Units as noted)
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	223,784	\$35.83/boe
	Heavy Oil (including solution gas and other by-products)	3,947	\$14.73/boe
	Natural Gas (including by-products but excluding solution gas from oil wells)	418,799	\$3.12/McfGE
	Coal Bed Methane	85,149	\$2.79/McfGE
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	319,215	\$32.65/boe
	Heavy Oil (including solution gas and other by-products)	6,191	\$13.09/boe
	Natural Gas (including by-products but excluding solution gas from oil wells)	621,713	\$2.86/McfGE
	Coal Bed Methane	102,393	\$2.61/McfGE

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.
2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Fairborne Reserve Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

Reserve Categories

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

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

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

- (a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
- (b) **Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

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

- (c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
 - (i) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
 - (ii) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- (d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

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

Levels of Certainty for Reported Reserves

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

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

A 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.

3. Forecast Prices and Costs

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by GLJ in the GLJ Report were GLJ's forecasts as at January 1, 2010, which were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS FORECAST PRICES AND COSTS

Year	OIL				NATURAL GAS			INFLATION RATES ⁽¹⁾ %/Year	EXCHANGE RATE ⁽²⁾ (\$US/\$Cdn)	
	WTI Cushing Oklahoma (\$US/Bbl)	Edmonton Par Price 40° API (\$Cdn/Bbl)	Hardisty Heavy 12° API (\$Cdn/Bbl)	Cromer Medium 29.3° API (\$Cdn/Bbl)	AECO Gas Price (\$Cdn/MMBtu)	Edmonton Propane (\$Cdn/Bbl)	Edmonton Butane (\$Cdn/Bbl)			Edmonton Pentanes Plus (\$Cdn/Bbl)
Forecast										
2010	80.00	83.26	64.99	76.60	5.96	52.46	64.11	84.93	2.0	0.95
2011	83.00	86.42	65.24	78.64	6.79	54.45	66.54	88.15	2.0	0.95
2012	86.00	89.58	65.33	80.62	6.89	56.43	68.98	91.37	2.0	0.95
2013	89.00	92.74	65.26	82.54	6.95	58.42	71.41	94.59	2.0	0.95
2014	92.00	95.90	67.52	85.35	7.05	60.42	73.84	97.82	2.0	0.95
2015	93.84	97.84	68.90	87.07	7.16	61.64	75.33	99.79	2.0	0.95
2016	95.72	99.81	70.32	88.83	7.42	62.88	76.85	101.81	2.0	0.95
2017	97.64	101.83	71.76	90.63	7.95	64.15	78.41	103.86	2.0	0.95
2018	99.59	103.88	73.22	92.46	8.52	65.45	79.99	105.96	2.0	0.95
2019	101.58	105.98	74.72	94.32	8.69	66.77	81.60	108.10	2.0	0.95
Thereafter	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0	0.95

Notes:

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

Weighted average historical prices realized by us for the year ended December 31, 2009, were \$5.74/Mcf for natural gas, \$65.50/Bbl for crude oil and \$31.10/Bbl for natural gas liquids.

4. Estimated future abandonment costs related to a property have been taken into account by GLJ 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 and reclamation of any facilities.

5. The forecast price and cost assumptions assume the continuance of current laws and regulations.
6. The extent and character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.
7. On March 11, 2010 the Alberta government announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the oil and natural gas industry, which included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month and certain temporary incentive programs currently in place being made permanent. See "*Industry Conditions*". Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months. Reserves and net present values reflected in the above tables do not reflect the potential effect of these new changes to Alberta's royalty system and no sensitivities were provided by GLJ as to the potential impact of same.

Reconciliation of Changes in Reserves

The following table sets out the reconciliation of our gross reserves as at December 31, 2008 compared to December 31, 2009 based on forecast prices and costs by principal product type:

FACTORS	LIGHT AND MEDIUM OIL			HEAVY OIL			CONVENTIONAL NATURAL GAS		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcft)	Gross Probable (MMcft)	Gross Proved Plus Probable (MMcft)
December 31, 2008	6,265	3,505	9,770	367	266	634	136,611	88,827	225,438
Extensions and Improved Recovery	682	610	1,292	0	0	0	1,138	1,546	2,684
Technical Revisions	478	(375)	103	5	(3)	2	3,077	(12,315)	(9,239)
Discoveries	0	0	0	0	0	0	15,019	9,290	24,309
Acquisitions	0	0	0	0	0	0	1,617	491	2,108
Dispositions	(4)	(1)	(4)	(64)	(36)	(99)	(3,614)	(4,810)	(8,424)
Economic Factors	0	0	0	0	0	0	0	0	0
Production	(1,206)	0	(1,206)	(24)	0	(24)	(18,376)	0	(18,376)
December 31, 2009	<u>6,216</u>	<u>3,738</u>	<u>9,954</u>	<u>285</u>	<u>228</u>	<u>512</u>	<u>135,472</u>	<u>83,029</u>	<u>218,501</u>

FACTORS	NATURAL GAS LIQUIDS			COAL BED METHANE		
	Gross Proved (Mbbbl)	Gross Probable (Mbbbl)	Gross Proved Plus Probable (Mbbbl)	Gross Proved (MMcft)	Gross Probable (MMcft)	Gross Proved Plus Probable (MMcft)
December 31, 2008	5,608	3,971	9,579	31,063	9,788	40,851
Extensions and Improved Recovery	48	100	148	3,670	182	3,852
Technical Revisions	(180)	(447)	(627)	3,577	(151)	3,426
Discoveries	214	136	350	0	0	0
Acquisitions	16	5	20	0	0	0
Dispositions	(55)	(128)	(183)	0	0	0
Economic Factors	0	0	0	0	0	0
Production	(218)	0	(218)	(4,440)	0	(4,440)
December 31, 2009	<u>5,433</u>	<u>3,636</u>	<u>9,070</u>	<u>33,870</u>	<u>9,819</u>	<u>43,689</u>

Note:

- (1) Gross Reserves in the tables above are the Corporation's interest share before deduction of royalties and without including any royalty interests of the Corporation.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped reserves and the probable undeveloped reserves, each by product type, attributed to Fairborne's assets for the years ended December 31, 2009, 2008 and 2007 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

	Light and Medium Oil (Mbbbl)		Heavy Oil (Mbbbl)		Conventional Natural Gas (MMcf)		Coal Bed Methane (MMcf)		NGLs (Mbbbl)	
	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end
Prior	1,100	2,004	140	494	22,725	30,594	20,764	37,972	565	760
2007	0	962	0	376	12,876	26,971	1,582	16,408	743	1,529
2008	640	1,091	0	209	26,402	48,668	2,592	9,291	1,085	2,524
2009	542	1,345	4	128	18,700	51,302	5,670	7,130	584	2,425

Probable Undeveloped Reserves

	Light and Medium Oil (Mbbbl)		Heavy Oil (Mbbbl)		Conventional Natural Gas (MMcf)		Coal Bed Methane (MMcf)		NGLs (Mbbbl)	
	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end	First Attributed	Cumulative at Year-end
Prior	1,062	2,042	38	218	28,345	44,405	10,316	16,413	667	1,061
2007	0	894	0	259	17,873	43,896	1,919	5,369	704	1,869
2008	1,126	1,938	0	139	33,150	60,650	1,116	3,917	1,636	2,934
2009	920	2,308	1	98	21,831	57,197	1,850	2,920	664	2,817

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. The majority of undeveloped reserves are scheduled to be developed within the next two years. Fairborne has areas where multiple zones have been assigned reserves in a well. Once the producing zones are depleted, capital will be spent recompleting the well in another zone. Some of these expenditures are planned to occur in 2011 and beyond, the timing dictated by the predicted reserve life for the currently producing zones. A significant capital program is required for new wells in our Columbia/Harlech area. For this area we plan to develop proved and probable undeveloped reserves over a period of four years. This phasing will allow us to optimize capital allocation and facility utilization. A number of factors that could result in delayed or cancelled development are as follows:

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

Significant Factors or Uncertainties

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

production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

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

While we do not anticipate any significant economic factors or significant uncertainties will affect any particular components of the reserves data, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control (see "*Risk Factors*").

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 (\$000s):

Year	Forecast Prices and Costs	
	Proved Reserves (\$000s)	Proved Plus Probable Reserves (\$000s)
2010	63,508	72,093
2011	78,298	116,687
2012	41,783	89,133
2013	9,010	29,433
2014	410	16,339
Thereafter	764	3,400
Total: Undiscounted	193,773	327,085

We expect that the capital listed in the preceding table will be funded through internally generated cash flows and will not have any associated funding costs. Therefore, the cost of funding is not expected to have any effect on the disclosed reserves of future net revenue.

Other Oil and Gas Information

Principal Properties

The following is a description of our principal oil and natural gas properties as at December 31, 2009. Unless otherwise indicated, production stated is average production for 2009 received in respect of our working interest share before deduction of royalties. Unless otherwise specified, gross and net acres and well count information is as at December 31, 2009.

Fairborne spent \$74.4 million on drilling and completion activities in 2009 with a total of 53 wells drilled (42.1 net), resulting in 19 (13.8 net) natural gas wells, 21 (17.1 net) CBM wells and 13 (11.2 net) oil wells. Drilling activities during 2009 were focused primarily on Fairborne's Harlech, Clive, Sinclair and Deep Basin properties. The following is a more detailed breakdown of 2009 activity and Fairborne's principal planned operations by area for 2010.

Deep Basin Resource Area

In 2009, Fairborne expanded its interest in the Deep Basin Resource area with the development of its Cretaceous Wilrich Shoreface gas play. This gas resource area is located approximately 250 kilometres west of Edmonton, between Edson and Grand Prairie, Alberta. Fairborne's core properties in this area include Marlboro/Pine Creek, Wild River and Tower Creek.

Marlboro/Pine Creek

The Marlboro property is located approximately 200 km due west of Edmonton. Natural gas production is obtained from the Notikewin, Falher, Wilrich, Gething and Cadomin Formations at average drill depths of 3,000 metres.

Gas is processed at the CAMS Kaybob K3 and Nosehill facilities. At the end of 2009, Fairborne had 30 gross (18.6 net) producing wells and 196 km² of 3D seismic coverage on Corporation's lands.

In 2009 Fairborne accomplished the following: (i) substantially increased its land position to 40.3 gross (24.9 net) sections with a 72% average working interest, (ii) drilled five gross wells (3.9 net) at 100% success rate, (iii) increased production from 1,664 Boe/d at the end of 2008 to 2,041 Boe/d at the end of 2009, (iv) successfully drilled an industry first Wilrich horizontal well with initial production rate of 3.2 MMcf/d; which was followed by the drilling of two additional Wilrich horizontals with initial production rates ranging 3.5 to 4.5 MMcf/d, (v) successfully drilled a horizontal well in a Notikewin channel with a lateral length of 1,566 metres and average porosity of 9% with an initial production rate of 3.5 Mmcf/d. Fairborne plans to drill 12 (8.5 net) wells in 2010.

Wild River

The Wild River property is located approximately 250 km northwest of Edmonton. Sour gas production is obtained from the Blueridge A pool and the 8-14 Nisku E pool at average drill depths of 3,800 metres. Gas is processed at the Kaybob A facility. In 2009 Fairborne drilled an updip well on the Nisku E pool for future gas production from the Blueridge Formation or potential water injection at the Nisku level reservoir. Additionally in 2009, Fairborne successfully performed a workover of the 8-14 discovery well completing gas pay in the Blueridge reservoir. The gas from the Blueridge is commingled with the Nisku production and the well is producing at 5.5 MMcf/d as at March 1, 2010.

Tower Creek

The Tower Creek property is located approximately 300 km northwest of Edmonton. The property was acquired through Fairborne's acquisition of Grand Banks in June 2008. Sour gas production is obtained from a Leduc Pinnacle reef located at a drill depth of 4,800 metres. The pool was discovered in 2006 with the drilling of the 2-21-55-27W5 well. At the end of 2009 the well had produced over 17 Bcf of raw gas and averaged 18.6 MMcf/d of raw gas since start up in June 2007. Gas from the 2-21 well is processed at the CAMS Kaybob K3 sour gas plant. Fairborne has a 20.17% working interest in the 2-21 producing well.

Columbia/Harlech

The Columbia/Harlech property is located in the outer foothills trend of west central Alberta. The property is characterized by numerous stacked reservoir horizons located at depths ranging from 2,500 to 3,500 metres. The sedimentary section in this trend is commonly overpressured and contains condensate rich natural gas reservoirs in numerous stratigraphic and structural traps. Additionally, the shallower part of the section is made up of thick fluvial sandstone deposits at depths between 1,300 and 2,000 metres that contain both light oil and sweet natural gas accumulations.

Fairborne acquired the Columbia/Harlech undeveloped land base (approximately 37,000 gross acres) in 2004 through an asset sale from BP Canada. In 2009, Fairborne added 24 sections of new land holdings at Harlech resulting in a year end total of 106,900 gross acres (80,000 net). Over the past 5 years Fairborne has grown the property from less than 100 Boe/d at the time of acquisition, to 2009 year end daily production of 3,276 Boe/d including 14,271 Mcf/d and 897 Bbls/d in associated NGLs.

In November of 2009, Fairborne closed a transaction to sell a portion of its working interest in the West Pembina gas plant and associated facilities for proceeds of \$20 million. The transaction included the sale of approximately 18% working interest in the Gas Plant and associated facilities, leaving Fairborne a 5% interest in the plant and associated facilities. Under the terms of the agreement Fairborne has priority access to 75 million cubic feet per day of capacity in the Keyera sour gas system (West Pembina and Brazeau River Gas Plant and associated facilities) and a strategic partner for the infrastructure development of the Harlech area gas reservoirs located west of the gas plant.

Fairborne continued to develop its Nordegg gas resource play by defining drill targets with 3D seismic and using horizontal and multistage fracture technology. At year end Fairborne, with industry partners, had drilled its fifth Nordegg horizontal as a 9 km step out test on its western acreage block. The well reached total depth in December 2009 with plans for completion, production testing and tie in operations commencing in the first quarter 2010.

Fairborne plans to drill six (4.5 net) vertical wells in 2010. The vertical wells will target a combination of condensate rich natural gas accumulations in the Cardium, Viking, Mannville, Rock Creek and Nordegg reservoirs.

Harlech area lands recently received down spacing approval from the Energy Resources Conservation Board ("**ERCB**") for four wells per section with additional sour and sweet gas commingling. On a go forward basis this will allow sour Nordegg gas to be commingled with uphole sweet gas as one production stream in vertical wells. Additionally, in 2010 Fairborne will test the Cardium gas condensate shoreface trend at Harlech using horizontal multistage fracture technology.

Brazeau/Harlech – Belly River Oil

The Brazeau/Harlech Belly River oil producing fairway is located in west central Alberta, approximately 160 kilometres southwest of Edmonton. Fairborne explores for light oil in the Belly River section in two main areas. The first area is Brazeau/Peco where Fairborne has an 87.7% working interest in the Brazeau Belly River Unit #6 (the "**Brazeau Unit**") as well as various non-unitized wells in close proximity to the Brazeau Unit. The Brazeau Unit is one of the deepest Belly River oil fields in the basin and represents a 500 metre thick section of stacked fluvial traps with oil and gas reservoirs at various levels through the section. Fairborne drilled one Basal Belly River horizontal oil well in the fourth quarter 2009. Plans for completion, production testing and tie in operations on this well will commence in the first quarter 2010. Exit daily production for 2009 from Brazeau Unit was 910 Boe/d including 2,076 Mcf/d, of natural gas and 624 Bbls/d of oil and NGLs. The second area of Belly River oil production is located at Fairborne's Harlech Belly River B pool. Year end 2009 cumulative production from this pool was 453,000 Bbls of 42 API oil and 0.47 Bcf of natural gas. In 2010 Fairborne plans on drilling four (2.2 net) horizontal wells targeting light oil from the Basal Belly River sands. It is anticipated that both horizontal and multistage fracturing will improve recovery from these oil charged tight sandstones at Brazeau and Harlech.

Clive Area

Fairborne's interest in the Clive area, located approximately 50 kilometres northeast of Red Deer, Alberta, includes conventional crude oil and natural gas production from reservoirs developed in Devonian aged Nisku and Leduc reefs, as well as, sandstone reservoirs in the Belly River Formation. In addition, Fairborne has developed an extensive CBM project in the area, which targets sweet gas from coal reservoirs within the Upper Cretaceous Horseshoe Canyon Formation. Fairborne's land position in the Clive area includes 91,744 gross (67,903 net) acres of land, with approximately 36% of net acres currently undeveloped.

Clive (Units and Non-Unit Wells)

Fairborne's position in the conventional oil and natural gas production at Clive includes a working interest in the Clive Leduc (D3) Unit #1 and the Clive Nisku (D2) Unit #1 as well as non-unitized wells. Fairborne operates both units with a 93.9% and 98.9% unit interest respectively. All oil and gas is initially processed at an operated facility in the immediate vicinity, with gas then transported to the Nevis gas plant (operated by Duke Energy Corporation) for further processing and natural gas liquids recovery. In August 2008, Fairborne signed a definitive agreement with Enhance Energy Inc. ("**Enhance**") to develop and implement a CO₂ enhanced oil recovery project flood for the Clive oil field in the Leduc and Nisku reservoirs.

In November 2009 Fairborne announced that its enhanced oil recovery project in partnership with Enhance had received two significant funding incentives. Enhance signed a letter of intent with the Government of Alberta that awards the Alberta Carbon Trunk Line ("**ACTL**") project \$495 million in funding from the Carbon Capture and Storage program. The ACTL project was also awarded a total of \$63 million from the Federal Government's eco Energy Technology initiative and the Clean Energy Fund. The funding will help build the ACTL project, which initially consists of carbon capture near Fort Saskatchewan, a 240 kilometre pipeline that will transport carbon dioxide (CO₂), and CO₂ facilities necessary for a joint Fairborne and Enhance CO₂ flood project at Fairborne's Clive Field in central Alberta. Enhance will operate the pipeline and capture facilities. Fairborne will operate the enhanced oil recovery project at Clive.

The project is being designed to recover additional light oil from Nisku and Leduc reservoirs through CO₂ injection and extend the producing life of the Clive field by up to another 20 years. Subject to the terms and conditions of a previously announced agreement with Enhance that includes payment of earning capital, Fairborne will retain 60% of its current working interest and contingent resources. The oil produced will pay royalties and taxes to both the Government of Alberta and Freehold land owners over the life of the project. The CO₂ will then be permanently stored deep underground within the depleted oil pools. Fairborne has plans for additional enhanced oil recovery projects in the Clive area using CO₂ injection after the initial project is established.

Fairborne also has oil and gas production from the Wood River unit and non-unit Leduc and Nisku reservoirs plus conventional oil and gas wells at Haynes. In 2009, conventional oil and gas production from Clive area averaged 5,031 Mcf/d of natural gas and 708 Bbls/d of oil and NGLs.

Clive Coal Bed Methane (CBM)

Since its initial drilling program in 2003, Fairborne has developed an extensive CBM resource on its Clive property by drilling and recompleting 212 well bores. In 2009 Fairborne drilled and recompleted 20 (16.5 net) wells with a 100% success rate. Average net daily CBM production from this area in 2009 was 12,128 Mcf/d (2,021 Boe/d) of natural gas produced from the Horseshoe Canyon Formation.

Fairborne's development plan for 2010 is to drill approximately 27 (19 net) CBM/Belly River wells. Current CBM wells decline at rates of 8% to 12% and therefore are expected to have the effect of lessening the overall corporate decline rate for the next two to three years.

Sinclair, Manitoba

The Sinclair producing property is located in southwest Manitoba. Fairborne produces 40 API gravity oil from the Torquay and Bakken Formations (Three Forks Group) at drill depths of approximately 1,000m.

In 2009, Fairborne drilled and tied-in seven horizontal wells (7.0 net) in the Sinclair operating area (Sinclair, Antler, Frys, Kingsford, Weyburn), bringing Fairborne's 2009 average production from this area to 1,080 Boe/d.

Operating costs at Sinclair have been substantially reduced in 2009, as a result of a major infrastructure project that included a central battery, water disposal well, gathering pipelines and the electrification of wellsites. With the majority of Sinclair's production coming from horizontal wells drilled under the province's royalty holiday programs, there is also minimal royalty expense associated with this production. As a result, Sinclair represents Fairborne's highest netback, light oil property and is a focus for on-going development activities.

On December 1, 2009 Fairborne received regulatory approval from the Manitoba government for a two section waterflood designated as Sinclair Unit #4 –located in T 7, R29W1. To date, Sinclair Unit #4 has produced over 190,000 barrels of oil from the Three Forks Group. Waterflooding of the reservoir commenced on December 18, 2009 with two injector wells.

Fairborne holds 48 sections (41.8 net) of undeveloped land at Sinclair and plans to drill up to four horizontal wells per section to develop this resource. The Corporation currently has 50 producing wells at Sinclair and plans to drill ten (10.0) horizontals in 2010.

Minor Properties

In addition to the foregoing, Fairborne has an interest in other minor properties that contributed, in aggregate, 1,439 Boe/d of production in 2009.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we have a working interest as at December 31, 2009.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	309	202.3	80	60.0	540	353.9	103	52.3
British Columbia	-	-	-	-	-	-	2	.1
Manitoba	37	32.6	2	2.0	-	-	-	-
Saskatchewan	85	49.3	8	1.4	-	-	-	-
Total	431	284.2	90	63.4	540	353.9	105	52.4

Land Holdings Including Properties with No Attributed Reserves

The following table sets out our developed and undeveloped land holdings as at December 31, 2009.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	196,881	116,884	259,304	168,890	456,185	285,774
British Columbia	2,340	258	12,410	1,397	14,750	1,655
Manitoba	3,384	3,229	27,423	26,769	30,807	29,998
Saskatchewan	5,330	3,717	15,382	12,799	20,712	16,516
Total	207,935	124,088	314,519	209,855	522,454	333,943

We expect that rights to explore, develop and exploit 32,700 net acres of our undeveloped land holdings may expire by December 31, 2010. We plan to drill or submit application to continue selected portions of the above acreage.

Forward Contracts and Marketing

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

We periodically hedge the price on a portion of our crude oil and natural gas production. During 2009, our realized price for crude oil was increased by \$5.62 per barrel in the first quarter and was not significantly impacted throughout the remainder of the year as we hedged an average of 32 percent of total crude oil production during the twelve months ended December 31, 2009.

The prices received for natural gas were increased by \$1.24 per Mcf in the first quarter, increased by \$1.58 per Mcf in the second quarter, increased by \$2.17 per Mcf in the third quarter and increased by \$1.31 per Mcf in the fourth quarter as we hedged an average of 41 percent of total natural gas production during the twelve months ended December 31, 2009.

The following crude oil fixed price physical contracts were outstanding at December 31, 2009:

Remaining Term	Volume (Bbls/d)	Price (US\$ per Bbl)	Type	Settlement Index
Jan 1 – Dec 31, 2010	500	55.00 – 108.00	Collar	WTI
Jan 1 – Dec 31, 2010	500	55.00 – 103.00	Collar	WTI
Jan 1 – Dec 31, 2010	500	70.00 – 100.15	Collar	WTI

The following natural gas fixed price physical contracts were outstanding at December 31, 2009:

Remaining Term	Volume (GJ per day)	Price (CDN\$ per GJ)	Type	Settlement Index
Jan 1 – Mar 31, 2010	5,275	5.77	AECO Swap	AECO C Monthly
Jan 1 – Dec 31, 2010	5,000	5.86	AECO Swap	AECO C Monthly
Jan 1 – Dec 31, 2010	2,500	5.67	AECO Swap	AECO C Monthly
Jan 1 – Dec 31, 2010	1,500	5.90	AECO Swap	AECO C Monthly
Jan 1 – Dec 31, 2010	1,500	5.86	AECO Swap	AECO C Monthly
Jan 1 – Dec 31, 2010	1,500	5.88	AECO Swap	AECO C Monthly
Jan 1 – Dec 31, 2010	1,500	6.00	AECO Swap	AECO C Monthly
Jan 1 – Dec 31, 2010	4,000	6.00	AECO Swap	AECO C Monthly
Jan 1 – Dec 31, 2010	2,000	6.13	AECO Swap	AECO C Monthly
Jan 1 – Dec 31, 2010	2,000	6.15	AECO Swap	AECO C Monthly
Jan 1 – Dec 31, 2010	2,000	6.16	AECO Swap	AECO C Monthly

Additional Information Concerning Abandonment and Reclamation Costs

Well abandonment costs on existing and future reserve wells have been included in the economic forecasts contained in the GLJ Report, while well abandonment costs on non-reserves wells, pipelines, production facilities and site reclamation have been excluded.

Abandonment costs are estimated on an area by area basis by GLJ. The industry's historical costs are used when available. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. We currently have 753.9 net wells for which we expect to incur abandonment and reclamation costs.

The total abandonment cost in respect of proved reserves using forecast prices is \$21.2 million (undiscounted) and \$7.8 million (discounted at 10%). 100% of such amounts were deducted as abandonment costs in estimating our future net revenue as disclosed above.

The following table sets forth the abandonment costs deducted in the estimation of our future net revenue:

<u>Forecast Prices and Costs (Total Proved) (\$000s)</u>	
<u>Year</u>	<u>Abandonment Costs (Undiscounted)</u>
2010	896
2011	317
2012	466
Thereafter	19,548
Total Undiscounted	21,227
Total Discounted @ 10%	7,759

Tax Horizon

The Corporation was not required to pay any cash income taxes for the period ended December 31, 2009. Based on current estimates of the Corporation's future taxable income and levels of tax deductible expenditures, management believes that the Corporation will not be required to pay cash income taxes until 2011 or later.

Capital Expenditures

The following table summarizes capital expenditures related to our assets and activities for the year ended December 31, 2009:

	<u>\$000s</u>
Property acquisition costs	
Proved properties	5,196
Undeveloped properties	10,138
Exploration costs	15,857
Development costs	84,084
Dispositions	(30,040)
Corporate Assets	310
Total	85,545

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells associated with our assets in which Fairborne participated during the year ended December 31, 2009.

	<u>Exploratory Wells</u>		<u>Development Wells</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
Light and Medium Oil	3	3.0	8	7.7
Heavy Oil	-	-	2	0.5
Natural Gas	4	2.4	15	11.4
Coal Bed Methane	-	-	21	17.1
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	7	5.4	46	36.7

For details on the important current and likely exploration and development activities during 2010, see "Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties".

Production Estimates

The following tables sets out the volume of our production estimated for the year ended December 31, 2010, which is reflected in the estimate of gross proved reserves and gross probable reserves disclosed in the tables contained under "Disclosure of Reserves Data" above.

Reserves Category	Light And Medium Oil		Heavy Oil		Conventional Natural Gas		Coal Bed Methane		Natural Gas Liquids		Total	
	Gross (Bbls/d)	Net (Bbls/d)	Gross (Bbls/d)	Net (Bbls/d)	Gross (Mcf/d)	Net (Mcf/d)	Gross (Mcf/d)	Net (Mcf/d)	Gross (Bbls/d)	Net (Bbls/d)	Gross (BOE/d)	Net (BOE/d)
PROVED												
Columbia/Harlech	4	3	-	-	12,785	11,094	-	-	833	635	2,968	2,488
Other Properties	2,426	1,962	54	50	34,922	28,596	12,386	11,169	567	412	10,932	9,052
TOTAL PROVED	2,430	1,966	54	50	47,707	39,690	12,386	11,169	1,400	1,047	13,899	11,540
PROVED PLUS PROBABLE												
Columbia/Harlech	4	3	-	-	13,438	11,633	-	-	875	671	3,119	2,613
Other Properties	2,524	2,044	57	54	37,463	30,716	12,638	11,387	596	436	11,527	9,550
TOTAL PROVED PLUS PROBABLE	2,528	2,047	57	54	50,901	42,349	12,638	11,387	1,472	1,107	14,646	12,163

No other individual property accounts for more than 20% of the estimated production disclosed.

Production History

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

	2009			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production ⁽¹⁾				
Light and Medium Crude Oil (Bbls/d)	2,960	3,231	3,469	3,562
Heavy Oil (Bbls/d)	77	61	83	37
Conventional Gas (Mcf/d)	46,981	44,771	54,733	55,050
Coal Bed Methane (Mcf/d)	12,151	12,026	12,011	12,470
NGLs (Bbls/d)	617	563	632	572
Sulphur (tonnes/d)	33	100	64	93
Combined (BOE/d)	13,542	13,421	15,372	15,517
Average Price Received				
Light and Medium Crude Oil (\$/Bbl)	73.34	68.43	64.86	57.21
Heavy Oil (\$/Bbls)	71.85	64.25	55.76	34.38
Conventional Gas (\$/Mcf)	6.55	5.95	5.67	6.58
Coal Bed Methane (\$/Mcf)	3.56	2.79	3.62	5.54
NGLs (\$/Bbls)	37.91	32.19	26.86	27.24
Sulphur (\$/tonnes)	-	-	128.16	185.14
Combined (\$/BOE)	43.89	40.42	39.59	43.13
Royalties Paid				
Light and Medium Crude Oil (\$/Bbls)	11.86	9.16	9.56	8.58
Heavy Oil (\$/Bbls)	18.11	16.54	13.04	6.15
Conventional Gas (\$/Mcf)	0.12	(0.32)	(0.06)	0.86
Coal Bed Methane (\$/Mcf)	0.30	0.20	0.15	0.54
NGLs (\$/Bbls)	3.39	0.33	0.16	7.28
Sulphur (\$/tonnes)	4.42	0.38	14.20	7.97
Combined (\$/BOE)	3.55	1.40	2.19	5.78

	2009			
	Dec. 31	Sept. 30	June 30	Mar. 31
Transportation costs				
Light and Medium Crude Oil (\$/Bbls)	1.11	0.86	0.62	0.79
Heavy Oil (\$/Bbls)	-	-	-	-
Conventional Gas (\$/Mcf)	0.18	0.28	0.22	0.25
Coal Bed Methane (\$/Mcf)	-	-	-	-
NGLs (\$/Bbls)	1.32	2.79	0.85	2.23
Sulphur (\$/tonnes)	-	-	-	-
Combined (\$/BOE)	0.92	1.25	0.96	1.14
Operating Expenses				
Light and Medium Crude Oil (\$/Bbls)	12.39	10.42	11.10	14.87
Heavy Oil (\$/Bbls)	12.92	(26.57)	14.47	33.74
Conventional Gas (\$/Mcf)	1.46	1.70	2.07	2.24
Coal Bed Methane (\$/Mcf)	0.48	0.50	0.40	0.38
NGLs (\$/Bbls)	8.65	8.89	6.81	14.34
Sulphur (\$/tonnes)	112.42	26.11	(23.30)	28.89
Combined (\$/BOE)	8.75	9.05	10.44	12.47
Netback Received (\$/BOE) ⁽²⁾				
Light and Medium Crude Oil (\$/Bbls)	47.98	47.99	43.58	32.97
Heavy Oil (\$/Bbls)	40.82	74.28	28.25	(5.51)
Conventional Gas (\$/Mcf)	4.79	4.29	3.44	3.23
Coal Bed Methane (\$/Mcf)	2.78	2.09	3.07	4.62
NGLs (\$/Bbls)	24.55	20.18	19.04	3.39
Sulphur (\$/tonnes)	(116.84)	(26.49)	137.26	148.28
Combined (\$/BOE)	30.67	28.72	26.00	23.74

Notes:

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

The following table indicates average daily gross production from important fields in respect of our assets for the year ended December 31, 2009:

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Conventional Gas (Mcf/d)	Coal Bed Methane (Mcf/d)	NGLs (Bbls/d)	Sulphur (tonnes/d)	BOE (BOE/d)
Brazeau	522	-	2,144	-	103	-	982
West Pembina	35	-	1,755	-	14	22	363
Harlech	793	-	16,890	-	250	-	3,858
Clive	391	-	3,840	10,943	27	2	2,883
Peace River Arch	43	-	3,851	-	7	-	692
Wild River	3	-	4,694	-	6	22	814
Wood River	116	-	772	477	17	19	361
Marlboro	75	-	9,777	-	77	-	1,781
Deep Basin	7	-	3,216	-	-	2	546
Pigeon Lake/Westerose	14	-	1,024	35	62	3	256
Haynes	142	-	419	708	15	2	347
Basset Lake	3	-	611	-	-	-	105
Miscellaneous	68	-	1,353	-	16	-	310
Total Alberta	2,212	-	50,346	12,163	594	72	13,298
Sinclair	773	-	-	-	2	-	773
Total Manitoba	773	-	-	-	-	-	-
Weyburn	161	-	-	-	-	-	161
Kingsford	146	-	-	-	-	-	146
Miscellaneous	-	64	-	-	-	-	64
Total Saskatchewan	307	64	-	-	-	-	371
U.S.	12	-	-	-	-	-	12
Total	3,304	64	50,346	12,163	596	72	14,454

Crude oil production from our assets for the year ended December 31, 2009 was 98% light and medium quality crude oil (25° API or greater) and 2% heavy crude oil (less than 15° API).

For the twelve months ended December 31, 2009, approximately 67% of gross revenue from our assets was derived from natural gas production and 33% was derived from crude oil production.

DIVIDENDS AND DISTRIBUTIONS

Dividend History

Fairborne has not paid any dividends on the outstanding Common Shares. The Board of Directors of Fairborne will determine the actual timing, payment and amount of dividends, if any, that may be paid by Fairborne from time to time based upon, among other things, the cash flow, results of operations and financial conditions of Fairborne, the need for funds to finance ongoing operations and other business considerations as the Board of Directors of Fairborne considers relevant.

Distribution History

Prior to the completion of the 2007 Reorganization, the following cash distributions were paid by the Trust to Trust Unitholders for the periods indicated:

For the Month Ending	Cash Distribution Per Unit		
	2007	2006	2005
January	\$0.13	\$0.13	-
February	\$0.13	\$0.13	-
March	\$0.09	\$0.13	-
April	\$0.09	\$0.13	-
May	\$0.09	\$0.13	-
June	\$0.09	\$0.13	\$0.11
July	\$0.09	\$0.13	\$0.11
August	\$0.09	\$0.13	\$0.11
September	\$0.09	\$0.13	\$0.11
October	\$0.09	\$0.13	\$0.11
November	\$0.09	\$0.13	\$0.13
December	-	\$0.13	\$0.13

DESCRIPTION OF CAPITAL STRUCTURE

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

Common Shares

Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Fairborne, to receive dividends if, as and when declared by the board of directors of Fairborne and to receive pro rata the remaining property and assets of Fairborne upon its dissolution or winding-up, subject to the rights of shares having priority over the Common Shares.

Preferred Shares

Each series of preferred shares shall consist of such number of shares and having such rights, privileges, restrictions and conditions as may be determined by the board of directors of Fairborne prior to the issuance thereof. Holders of preferred shares, except as required by law, will not be entitled to vote at meetings of shareholders of Fairborne. With respect to the payment of dividends and distribution of assets in the event of liquidation, dissolution or winding-up of Fairborne, whether voluntary or involuntary, the preferred shares are entitled to preference over the Common Shares and any other shares ranking junior to the preferred shares from time to time and may also be given such other preferences over the Common Shares and any other shares ranking junior to the preferred shares as may be determined at the time of creation of such series. At the date hereof, no series of preferred shares has been created.

BORROWINGS

Credit Facilities

As at December 31, 2009 and as at the date hereof, the Corporation's credit facilities consist of a \$270 million extendible revolving term credit facility and a \$15 million demand operating credit facility available from a syndicate of Canadian chartered banks, subject to the banks' semi-annual valuation of Fairborne's petroleum and natural gas properties. The extendible revolving term facility is available on a revolving basis until May 28, 2010 (364 day facility) at which time it may be extended, at the lenders option. If the revolving period is not extended, the undrawn portion of the facility will be cancelled and the amount outstanding will convert to a 365 day non-revolving term facility. The amounts outstanding under the non-revolving term facility are required to be repaid at the end of the term facility being May 28, 2011. Interest payable on amounts drawn under the facilities is at the prevailing bankers' acceptance rates plus stamping fees, lenders' prime rate or LIBOR rates plus applicable margins, depending on the form of borrowing by the Corporation. The margins and stamping fees vary from 0.75% to 4.25% depending on financial statement ratios and the form of borrowing. The credit facilities are secured by a general security agreement and a first ranking floating charge on the assets of the Corporation.

Debentures

On October 31, 2006 the Trust completed a public offering of Debentures by way of short form prospectus for aggregate gross proceeds of \$100 million. The Debentures have a face value of \$1,000 per Debenture and have a maturity date of December 31, 2011 (the "**Maturity Date**"). The Debentures bear interest at the rate of 6.50% per annum, which is payable semi-annually in arrears on December 31 and June 30 of each year. Pursuant to the 2007 Reorganization, the Corporation assumed all of the covenants and obligations of the Trust under the outstanding Debentures.

The Debentures are redeemable by the Corporation in whole or in part at a price of \$1,050 per Debenture until December 31, 2010 and at a price of \$1,025 per Debenture from December 31, 2010 to the Maturity Date, in each case, plus accrued and unpaid interest thereon. Each Debenture is convertible into Common Shares at the option of the holder at any time prior to the close of business on the earlier of the Maturity Date and the business day immediately preceding the date specified by the Corporation for redemption of the Debentures, at a conversion price of \$13.50 per Common Share, subject to adjustment upon the occurrence of certain events as described in the Debenture Indenture.

Upon the maturity or redemption of the Debentures, the Corporation may pay the outstanding principal of and premium (if any) on the Debentures in cash or may, at its option, on not greater than 60 days and not less than 40 days prior notice and subject to regulatory approval, elect to satisfy its obligations to repay all or a portion of the principal amount of the Debentures which have matured or been redeemed by issuing and delivering that number of Common Shares obtained by dividing the aggregate principal of principal and premium (if any) on the Debentures which have matured or redeemed by 95% of the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date fixed for redemption or the Maturity Date, as the case may be. Any accrued and unpaid interest thereon will be paid in cash.

Within 30 days following the occurrence of a change of control of the Corporation involving the acquisition of voting control or direction over 66 $\frac{2}{3}$ % or more of the Common Shares or securities convertible into or carrying a right to acquire Trust Units (a "**Change of Control**"), the Corporation will be required to make an offer in writing to purchase all of the Debentures then outstanding (the "**Debenture Offer**"), at a price equal to 101% of the principal amount thereof plus accrued and unpaid interest thereon. If 90% or more of the aggregate principal amount of the Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered to the Corporation pursuant to the Debenture Offer, the Corporation will have the right to redeem all the remaining Debentures at the same offer price.

The following table summarizes certain terms of the Debentures including the principal amount outstanding as of March 2, 2010:

<u>Maturity Date</u>	<u>Interest Rate at Date of Issue</u>	<u>Principal Amount Outstanding</u>	<u>Conversion Price per Common Share</u>	<u>Number of Common Shares Reserved</u>
December 31, 2011	6.50%	\$100,000,000	\$13.50	7,407,407

For a complete description of the terms of the Debentures, a copy of the Debenture Indenture has been filed on www.sedar.com under the Corporation's SEDAR profile.

MARKET FOR SECURITIES

The Common Shares and the Debentures are listed and posted for trading on the TSX under the symbols "FEL" and "FEL.DB", respectively.

The following sets forth trading information for the Common Shares as reported by the TSX for the periods indicated:

<u>Period</u>	<u>High (\$)</u>	<u>Low (\$)</u>	<u>Volume</u>
<u>2009</u>			
January	7.16	4.02	15,620,862
February.....	4.95	2.47	13,439,666
March	3.67	2.33	42,235,562
April	4.95	2.88	25,436,392
May.....	6.05	4.21	18,413,426
June.....	4.85	3.60	14,232,837
July	3.69	3.05	8,015,847
August	3.87	3.21	9,895,337
September.....	5.11	3.43	19,116,947
October.....	5.21	4.06	12,957,335
November.....	4.96	4.24	11,397,578
December.....	5.01	4.27	6,384,915
<u>2010</u>			
January	5.63	4.77	11,067,184
February.....	5.06	4.27	13,835,386
March (1-11).....	4.45	4.00	11,858,600

The following sets forth trading information for the Debentures as reported by the TSX for the periods indicated:

<u>Period</u>	<u>High (\$)</u>	<u>Low (\$)</u>	<u>Volume</u>
<u>2009</u>			
January	83.00	74.00	69,685
February.....	79.95	68.00	33,250
March	75.00	67.00	28,350
April	82.00	72.50	109,740
May	88.25	84.00	39,740
June	89.50	87.01	119,900
July.....	91.00	87.75	44,040
August.....	95.00	90.02	21,960
September	98.00	93.25	101,580
October.....	101.00	96.02	39,060
November.....	100.39	98.25	39,740
December	100.75	99.00	85,040
<u>2010</u>			
January	102.99	100.00	25,540
February.....	101.99	100.75	52,320
March (1-11).....	101.95	101.25	756,000

ESCROWED SECURITIES

There are no securities of the Corporation currently held in escrow.

DIRECTORS AND OFFICERS

The following table sets forth the name, age, province or state and country of residence, date first elected as a director of Fairborne where applicable and office held for each of the directors and officers of Fairborne together with their principal occupations during the last five years. The directors of Fairborne shall hold office until the next annual meeting of shareholders or until their respective successors have been duly elected or appointed.

Name, Age, Province or State and Country of Residence	Office Held	Date First Elected or Appointed as Director of Fairborne	Principal Occupation
Richard A. Walls ⁽²⁾⁽⁵⁾ Alberta, Canada Age: 61	Chairman and a Director	January 9, 2002	Chairman of Fairborne since May, 2005; President and Chief Executive Officer of Fairquest from May, 2005 to June, 2007; prior thereto, President and Chief Executive Officer of Fairborne from May 2002 to May 2005; prior thereto, special advisor to Duke Energy Field Services Canada Ltd. (" Duke Energy ") from May 2001 to January 2002; prior thereto, from April 1999 to May 2001 President and Chief Executive Officer of Canadian Midstream Services Ltd. (" CMSL ") (a private oil and natural gas midstream company); and prior thereto, from July 1993 to November 1998 President and Chief Executive Officer of Pan East Petroleum Corp. (" Pan East ") (a public oil and natural gas company).
Steven R. VanSickle Alberta, Canada Age: 45	President and Chief Executive Officer and a Director	May 30, 2005	President and Chief Executive Officer of Fairborne since May, 2005; prior thereto, Senior Vice-President, Exploration of Fairborne from May 2002 to May 2005; prior thereto, Vice-President, Business Development of Duke Energy from May 2001 to May 2002; prior thereto, Vice-President, Business Development of CMSL from April 1999 to May 2001; and prior thereto, Manager, Business Development of PanEast from January 1998 to November 1998.
Greg Bay ⁽¹⁾⁽³⁾ British Columbia, Canada Age: 51	Director	September 15, 2008	Founding partner, President & CEO of Cypress Capital Management (from 1998 to present).
Robert B. Hodgins ⁽¹⁾⁽²⁾⁽⁴⁾ Alberta, Canada Age: 58	Director	May 30, 2005	Private investor and corporate director since 2004; prior thereto, Chief Financial Officer of Pengrowth Energy Trust from 2002 to 2004; prior thereto from 1998 to 2002, Vice President and Treasurer of Canadian Pacific Limited; and prior thereto, Chief Financial Officer of TransCanada PipeLines Limited from 1993 to 1998 and held various other senior positions at TransCanada commencing in 1981.
Johannes J. Nieuwenburg ⁽²⁾⁽³⁾⁽⁵⁾ Alberta, Canada Age: 55	Lead Director	May 30, 2005	General Partner of Kern Partners Ltd., a private investment firm, since October, 2008 and private businessman and corporate director since 2001; prior thereto, President and Chief Executive Officer of Petromet Resources Limited from May, 1998 to May, 2001 and Executive Vice President and Chief Operating Officer thereof from March, 1998; prior thereto, Vice President, Asset Management of Norcen Energy Resources Limited from March, 1997 to March, 1998; and prior thereto, held various positions with Amoco Energy Group, North America from May, 1980 to March, 1997, with the last position being General Manager, Business Development.

Name, Age, Province or State and Country of Residence	Office Held	Date First Elected or Appointed as Director of Fairborne	Principal Occupation
Carl J. Tricoli ^{(4) (5)} Texas, USA Age: 54	Director	December 19, 2007	Founder and Managing Partner of Denham Capital Management LP and its predecessor since August 2004; prior thereto President of GeosCapital LLC from January 2002 to August 2004; prior thereto Vice President at Enron Corporation from April 1999 to January 2002; prior thereto Managing Director at Koch Industries from September 1997 to April 1999; prior thereto President of Black Hawk Resources from August 1996 to September 1997; and prior thereto held various positions at NationsBank Capital Markets with the last position being Managing Director and Head of Energy Corporate Finance.
Rodney D. Wimer ⁽¹⁾⁽³⁾⁽⁴⁾ Oregon, USA Age: 60	Director	May 31, 2002	President, Mazama Capital Partners (a private investment firm) since January 2002; prior thereto, from March 2001 to January 2002, President, Commercial Power Division of Dynege, Inc. and from January 1997 to March 2001, President and Chief Executive Officer of Dynege Canada Inc.
David L. Summers Alberta, Canada Age: 51	Chief Operating Officer	N/A	Chief Operating Officer of Fairborne since May, 2005; prior thereto, Vice-President, Operations and Chief Operating Officer of Fairborne from May 2002 to May 2005; prior thereto, Senior Vice-President of Commercial and Operations of Duke Energy from May 2001 until May 2002; prior thereto, Vice-President, Operations and Chief Operating Officer of CMSL from April 1999 to May 2001; and prior thereto, Vice-President, Operations of PanEast from October 1997 to November 1998 and Chief Operating Officer of PanEast from June 1998 to November 1998.
Aaron G. Grandberg Alberta, Canada Age: 39	Chief Financial Officer	N/A	Chief Financial Officer of Fairborne since June 2005 and Vice-President, Finance of Fairborne from June 2005 to March 2007; prior thereto, Controller of NAL Oil & Gas Trust since December 1999; prior thereto, Manager of Financial Reporting for NAL Oil & Gas Trust; and prior thereto, Mr. Grandberg was employed for five years with a national accounting firm. Mr. Grandberg received his Chartered Accountant designation in 1997.
Scott Hadley Alberta, Canada Age: 47	Vice-President, Exploration	N/A	Vice-President, Exploration of Fairborne since December 2007; prior thereto, Manager, Exploration of Fairborne Energy Trust since May 2007; prior thereto, Chief Geologist of Fairborne since May 2004; prior thereto, Senior Geologist of Fairborne since May 2002; prior thereto, Manager Exploration of Range Energy Inc. since July 1998; and prior thereto and from July 1997 Staff Petrophysicist for the Amoco Canada Exploration and Production Technology Group.
David E.T. Pyke Alberta, Canada Age: 55	Vice-President, Land	N/A	Vice-President, Land of Fairborne since July 2003; prior thereto, Vice-President Land of Pivotal since January 2003 and prior thereto Vice-President, Land and Contracts of Cigar Oil & Gas Ltd., a predecessor of Pivotal from January 1999; prior thereto and from October 1998, businessman; prior thereto and from August 1997, Vice President Land and Contracts of Barrington Petroleum Ltd. (a public oil and natural gas company); and prior thereto and from April 1996, Vice President Business Development of AEC Oil & Gas Ltd. (a public oil and natural gas company).
Gary M. Poirier Alberta, Canada	Vice-President, Production	N/A	Vice-President, Production of Fairborne since August 2004; prior thereto, Manager of Operations and

Name, Age, Province or State and Country of Residence	Office Held	Date First Elected or Appointed as Director of Fairborne	Principal Occupation
Age: 47			Engineering of Fairborne since May 2002; prior thereto and from August 2000, Operations Manager at Dominion Energy Canada Ltd.; and prior thereto and from March 1997, Business Unit Manager for the Yellowhead and Eastern business units of Mobil Oil Canada.
David S. Cymbalisky Alberta, Canada Age: 46	Vice-President, Engineering	N/A	Vice-President, Engineering of Fairborne since August, 2004; prior thereto Manager of Drilling and Completions of Fairborne since October 2003; prior thereto and since August 2002, Vice-President, Engineering and Chief Environmental Safety Officer of Pivotal; and prior thereto and since September 2001, President of Pan Ridge Oil Corp., a private oil and gas company; and prior thereto and from December 1998, Vice-President, Operations at Ionic Energy Inc.
F. Tom Park Alberta, Canada Age: 40	Vice-President, Marketing	N/A	Vice-President, Marketing of Fairborne since March 2005; prior thereto Director, Producer Origination & Financial Products of BP Canada Energy Company from March 2001; and prior thereto and from December 1998, Supervisor, Gas Supply & Operations, Berkley Petroleum Corp.
Jacqueline M. Cugnet⁽⁷⁾ Alberta, Canada Age: 41	Vice-President, Finance	N/A	Vice-President, Finance of Fairborne since March 2007; prior thereto Manager of Taxation and Special Projects of Fairborne from September 2004; prior thereto Vice-President, Finance and Chief Financial Officer of Questerre Energy Corp., from August 2003; and prior thereto and from June 2002, Vice-President, Finance and Chief Financial Officer of Pivotal; prior thereto and from January 2000 financial consultant; and prior thereto and since August 1994, Controller, Summit Resources Ltd.
C. Steven Cohen Alberta, Canada Age: 54	Secretary	N/A	Partner with Burnet, Duckworth & Palmer LLP (barristers and solicitors)

Notes:

- (1) Member of Audit Committee.
- (2) Member of Reserves Committee.
- (3) Member of Compensation Committee.
- (4) Member of Corporate Governance Committee.
- (5) Member of Risk Management Committee.
- (6) The term of office of all directors will expire on the date of the next annual meeting of holders of Common Shares.
- (7) Ms. Cugnet was Vice-President, Finance and Chief Financial Officer of Questerre Energy Corporation ("Questerre") in 2003 when Questerre made a proposal under the Company Creditors' Arrangement Act (Canada) to settle outstanding liabilities, which proposal received court and creditor approval and was implemented.

As at March 1, 2010, the directors and officers of Fairborne, as a group, beneficially owned, or controlled or directed, directly or indirectly, an aggregate of 6,114,311 Common Shares, representing approximately 6% of the issued and outstanding Common Shares.

Conflicts of Interest

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

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

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

Composition of the Audit Committee

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

<u>Name</u>	<u>Independent</u>	<u>Financially literate</u>	<u>Relevant education and experience</u>
Robert B. Hodgins	Yes	Yes	Mr. Hodgins is a Chartered Accountant (Ontario and Alberta) and holds a Bachelor of Arts in Business from the Richard Ivey School of Business. Mr. Hodgins' career culminated in an executive role following a career that spanned more than 25 years with several senior Canadian corporations and is an investor and a corporate director. Most recently, from 2002 to 2004, he served as the Chief Financial Officer of Pengrowth Energy Trust. Beginning in April 1998 until October 2001, he was Vice President and Treasurer of Canadian Pacific Limited. Prior to that he was the Chief Financial Officer of TransCanada PipeLines Limited from 1993 to 1998 and held various other senior positions at TransCanada commencing in 1981. Mr. Hodgins is also a director of Orion Oil & Gas Corporation., Enerplus Resources Fund, MGM Energy Corp as well as Altagas General Partner Inc.
Greg Bay	Yes	Yes	Mr. Bay obtained his chartered Financial Analyst Designation in 1988 and holds a Bachelor of Commerce in Finance from Brigham Young University. Mr. Bay is the President and CEO of Cypress Capital Management (founding partner) and brings with him over 25 years of experience in the investment industry with emphasis on the oil and gas sector. Mr. Bay also holds director positions with the Mullen Group Income Fund, Lions Gate Hospital Foundation Investment Committee, Bellamont Exploration Ltd and the University of British Columbia Industry Liaison Board; he is also a board member of Priviti Capital Corporation, a private investment firm that focuses on investments in private energy companies.
Rodney D. Wimer	Yes	Yes	Mr. Wimer is a graduate of the Stanford University Executive Program. Mr. Wimer is the Managing Director of Mazama Capital Partners (a private investment firm). Mr. Wimer serves as a director of Capital Power Income LP and is a limited partner and non voting advisory director of Fulcrum Power Services LP.

Pre-Approval of Policies and Procedures

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

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

External Auditor Service Fees

Audit Fees

The aggregate fees billed by our external auditor in each of the last two fiscal years for audit services and the reviews of interim financial statements were \$193,000 in 2009 and \$190,000 in 2008.

Audit – Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance related services by our external auditor that are reasonably related to the performance of the audit or review of our financial statements that are not reported under "Audit Fees" above were \$60,000 in 2009 and \$75,334 in 2008. These services relate to securities filings including short form prospectuses, business acquisition reports, French translation of financial statements and management discussion and analysis and information circulars.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by our external auditor for tax compliance, tax advice and tax planning were \$10,250 in 2009 and \$43,443 in 2008.

All Other Fees

The aggregate fees billed in the 2009 fiscal year for other services were \$35,000 and \$15,000 in the 2008 fiscal year and were related to consultations on the application of international financial reporting standards.

INDUSTRY CONDITIONS

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

Pricing and Marketing

Oil

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

Natural Gas

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

The governments of Alberta, 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. As yet, Manitoba does not have natural gas production in commercial quantities and does not therefore impose such export restrictions.

Pipeline Capacity

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production of oil and natural gas in western Canada and pipeline capacity does not limit the ability to produce and to market oil and natural gas production. The pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon 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 voluntary measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, that any prohibition in any circumstances in which any other form of quantitative restriction is applied is prohibited, and in the case of import-price requirements, that such requirements do not apply with respect to enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes, minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

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

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

Alberta

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

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors; specifically, the maximum royalty rates for conventional oil and natural gas production will be decreased effective for the January 2011 production month and certain temporary incentive programs currently in place will be made permanent. Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF range from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps are set at \$120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 40%.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF range from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps are set at \$17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 36%.

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

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "IETP"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a \$200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 m 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 m provides a sliding scale royalty credit based on depth of up to \$3,750 per metre.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

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

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

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia 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. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty

rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

As at the beginning of 2009, British Columbia maintained a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to \$100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;
- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 m and horizontal wells with a true vertical depth greater than 2,300 m spud between December 1, 2003 and September 1, 2009;
- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 m and a re-entry date subsequent to December 1, 2003;
- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m³ of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 m whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;
- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m³ as well as a royalty credit for coalbed gas wells equal to \$50,000 for wells drilled on Crown land and a tax credit equal to \$30,000 for wells drilled on freehold land;
- *Marginal Royalty Reduction Program* providing royalty breaks for low productivity natural gas wells with average monthly production under 25,000 m³ during the first 12 production months and average daily production less than 23 m³ for every metre of marginal well depth;
- *Ultra-Marginal Royalty Reduction Program* providing additional royalty breaks for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m³ during the first 12 production months and average daily production less than 11.5 m³ (development wells) or 17 m³ (exploratory wildcat wells) for every 100 m of marginal well depth;
- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well event on either Crown or freehold land and completed in a new pool discovery subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m³ of production, whichever comes first.

On March 2, 2009, the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which allocates \$120 million in royalty credits for oil and gas companies. The Infrastructure Royalty Credit Program provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. The Government of British Columbia has recently announced the same level of funding for the 2010 Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty

initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. Wells spud between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An additional \$50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

In Saskatchewan, the amount payable as a royalty 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 a royalty in respect of natural gas production is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas is 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.

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 provide 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 m 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 m or within certain formations);
- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;
- *Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005* providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout; and
- *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.

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.

Manitoba

In Manitoba, the royalty amount payable on oil produced from Crown lands depends on the classification of the oil produced as "old oil" (produced from a well drilled prior to April 1, 1974 that does not qualify as new oil or third tier oil), "new oil" (oil that is not third tier oil and is produced from a well drilled on or after April 1, 1974 and prior to April 1, 1999, from an abandoned well re-entered during that period, from an old oil well as a result of an enhanced recovery project implemented during that period, or from a horizontal well), "third tier oil" (oil produced from a vertical well drilled after April 1, 1999, an abandoned well re-entered after that date, an inactive vertical well activated after that date, a marginal well that has undergone a major workover, or from an old oil well or a new oil well as a result of an enhanced recovery project implemented after that date), or "holiday oil" (oil that is exempt from any royalty or tax payable). Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order from the Minister. For horizontal wells, the royalty on oil produced from Crown lands is calculated based on the amount of oil production allocated to a spacing unit in accordance with the applicable regulations.

Royalties payable on natural gas production from Crown lands are equal to 12.5% of the volume of natural gas sold.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. The freehold production tax payable on oil is calculated on a sliding scale based on the monthly production volume and the classification of oil as old oil, new oil, third tier oil and holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold. There is no freehold production tax payable on gas consumed as lease fuel.

The Government of Manitoba maintains a Drilling Incentive Program (the "**Program**") with the intent of promoting investment in the sustainable development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume" pursuant to which no Crown royalties or freehold production taxes not payable until the holiday oil volume has been produced. Under the Program, wells drilled for purposes of injection (or wells converted to injection prior to producing predetermined volumes of oil) in an approved enhanced oil recovery project earn a one-year holiday for portions of the project area.

The Program consists of the following components:

- *New Well Incentive* provides licensees of newly drilled, non-horizontal wells drilled prior to January 1, 2014 with a holiday oil volume of 10,000 m³;
- *Deep Drilling Incentive* provides licensees who drill a well to a total depth sufficient to penetrate the Devonian Duperow formation with a holiday oil volume of 20,000 m³, and licensees who drill a well deeper than the Devonian Three Forks formation can make a one-time assignment of up to 10,000 m³ of holiday oil volume earned through previous drilling or major workovers to such well's holiday oil volume;
- *Horizontal Well Initiative* provides licensees of horizontal wells drilled prior to January 1, 2014 with a holiday oil volume of 10,000 m³, and a horizontal leg drilled from an existing horizontal well on or after January 1, 2009 and prior to January 1, 2014 will earn an additional holiday royalty volume of 3,000 m³;
- *Marginal Well Major Workover Incentive* provides licensees of marginal wells where a major workover is completed prior to January 1, 2014 with a holiday oil volume of 500 m³, with a marginal oil well defined as an abandoned well or a well that was either not operated over the previous 12 months or produced oil at an average rate of less than 1 m³ per operating day;
- *Injection Well Incentive* provides a one year exemption from the payment of Crown royalties or freehold production taxes on production allocated to a unit tract in which a well is drilled or converted to water injection;

Further, holiday oil volumes earned by a newly drilled well, or a marginal well that has undergone a major workover can be transferred to a Holiday Oil Volume Account ("**Account**") at the request of the licensee, the purpose of which is to optimize the value of holiday oil volumes earned by providing a company with the flexibility of allocating holiday oil volumes earned among new wells.

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 from two years, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

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

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides, for the first time in western Canada, for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be

implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licenses that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

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

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations in order for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

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

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

establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

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

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

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both greenhouse gases and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives the Government of Canada have recently indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. The approach of the United States is expected to include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the Updated Action Plan. As a result, many provisions of the Updated Action Plan, described below, are expected to be significantly modified.

The stated goal of the Updated Action Plan, as currently drafted, is to reduce greenhouse gas emissions to 20% below 2006 levels by 2020 and 60-70% by 2050. As noted above, the goal has now been modified by the Government of Canada. The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets applied to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 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: Technology Fund contributions, offset credits, clean development credits and credits for early action. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution

rate for Technology Fund contributions will increase over time, beginning at \$15 tonnes per CO₂ equivalent for the 2010-12 period, rising to \$20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

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

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

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

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on July 1, 2007, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to comply with the CCEMA. Similarly to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Existing Facilities" and "New Facilities". Existing Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2008 or that have completed 8 or more years of commercial operation. Existing Facilities were required to reduce their emissions intensity by March 31, 2008 by 12% from a baseline established by their average emissions intensity between 2003 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation subsequent to December 31, 2008, have completed less than 8 years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are also required to reduce their emissions intensity by 12% but this target is based on the emissions intensity of the facility in its third year of commercial operation and does not apply during the first 3 years of operation of the New Facility. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements beyond the 12% emissions intensity required.

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

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at \$10 per tonne of CO₂ equivalent and rose to \$15 per tonne of CO₂ equivalent on July 1, 2009. It is scheduled to further increase at a rate of \$5 per tonne of CO₂ equivalent on July 1 of every year until it reaches \$30 per tonne of CO₂ equivalent on July 31, 2012. In order to make the tax

revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and will come into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on greenhouse gas emissions. It is expected that greenhouse gas emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO₂ equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in greenhouse gas emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO₂ equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO₂ equivalents per year are required to have their emissions reports verified by a third party.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate greenhouse gas emissions in the province. Although the MRGGA has only passed first reading in the Saskatchewan legislature and the specific details of the legislation have not yet been determined, it is expected that the MRGGA will adopt the goal of a 20% reduction in greenhouse gas emissions by 2020 and permit the use of technology fund contributions 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.

Manitoba

The Government of Manitoba has recently indicated its intention to commence public consultations with respect to the development of a cap and trade system to reduce greenhouse gas emissions. No legislation with respect to climate change is currently in effect.

RISK FACTORS

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

Exploration, Development and Production Risks

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

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

production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

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

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

Prices, Markets and Marketing

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

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

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

sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

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

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

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

Operational Dependence

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

Project Risks

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

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

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

Competition

The petroleum industry is competitive in all its phases. The Corporation competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and

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

Regulatory

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

Environmental

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

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so called "greenhouse gases". Recently, representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets slightly. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with Alberta's greenhouse gas emissions legislation contained in the Climate Change and Emissions Management Act and the Specified Gas Emitters Regulation. The Corporation may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency 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 required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. Given the evolving nature of the debate related to climate change and the control of 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 gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators.

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

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

Substantial Capital Requirements

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

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Corporation may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Corporation's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Corporation. Continued uncertainty in domestic and international credit markets could materially affect the Corporation's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Corporation's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

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

Hedging

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

compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Corporation will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

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

Title to Assets

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

Reserve Estimates

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

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

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

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

Insurance

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

circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geo-Political Risks

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

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

Dilution

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

Management of Growth

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

Expiration of Licences and Leases

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

Dividends

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

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada and have also made claims that certain developments, including oil and gas exploration development, may have been proceeding without the Crown carrying out appropriate consultations in the course of allowing such developments to proceed. An action has been commenced on behalf of the Sunchild First Nation ("Sunchild") against the Provincial Crown, various provincial ministries, the ERCB and numerous respondent oil and gas companies, including the Corporation, that appear to have interests in the area in question. Sunchild seeks judicial review of various Crown and ERCB decisions issued since June 30, 2008 in relation to what is claimed to be their traditional land, and which appears to include a significant portion of the foothills area of Alberta, on the basis that the Crown failed to properly consult and accommodate Sunchild, in the context of issuing licences to the oil and gas companies, forestry and coal companies within Sunchild's reserve and claimed foothills traditional lands area since the end of June, 2008. While the proceedings could result in a

change in the consultative and decision-making processes with respect to the granting of Crown rights and other licences in respect of the area or some portion of it, it is too early to assess the likelihood of such a possibility or its impact on the Corporation's future operations in this area.

Seasonality

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

Third Party Credit Risk

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

Conflicts of Interest

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

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. 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.

HUMAN RESOURCES

We currently employ 121 employees, of which 72 are located in the head office and 49 are field employees, and 13 consultants. We intend to add additional professional and administrative staff as the need arises.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Fairborne is not a party to any legal proceeding nor was it a party to, nor is or was any of its property the subject of any legal proceeding, during the financial year ended December 31, 2009, nor is Fairborne aware of any such contemplated legal proceedings, which involve a claim for damages exclusive of interest and costs that may exceed 10% of the current assets of Fairborne. See also "*Risk Factors – Aboriginal Claims*".

During the year ended December 31, 2009, there were no (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of Fairborne, any holder of Common Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year which has materially affected or is reasonably expected to materially affect Fairborne other than as follows:

1. Mr. Richard A. Walls, the Chairman and a director of Fairborne, was the President and Chief Executive Officer and director of Fairquest prior to completion of the Fairquest Arrangement. Mr. Walls received \$618,750 in connection with the termination of his employment with Fairquest upon completion of the Fairquest Arrangement. Mr. Walls also held (i) 150,000 options to acquire Common Shares of Fairquest ("**Fairquest Options**") which were terminated for no consideration immediately prior to completion of the Fairquest Arrangement and (ii) 650,000 common share purchase warrants of Fairquest ("**Fairquest Warrants**") which were exchanged for Trust Unit purchase warrants in conjunction with completion of the Fairquest Arrangement based upon the same exchange ratio that Fairquest Shares were exchanged for Trust Units under the Fairquest Arrangement.
2. The directors and officers of Fairborne and their associates and affiliates, as a group, owned, directly or indirectly, or exercised control or direction over, an aggregate of 5,378,256 Fairquest Shares (including Common Shares issued upon conversion of performance shares of Fairquest immediately prior to completion of the Fairquest Arrangement) which were exchanged for an aggregate of 2,097,520 Trust Units under the Fairquest Arrangement. In addition, such individuals held in the aggregate 440,000 Fairquest Options and 2,711,334 Fairquest Warrants which were treated in the same fashion as those held by Mr. Walls as described above.
3. The directors and officers of Fairborne and their associates and affiliates, as a group, owned, directly or indirectly, or exercised control or direction over, an aggregate of 6,540,006 Trust Units and 1,473,734 Exchangeable Shares which were exchanged for an aggregate of 8,543,267 Common Shares under the 2007 Reorganization. In addition, the directors and officers of Fairborne also held an aggregate of 1,067,070 Trust Unit purchase warrants of the Trust which were adjusted so as to be exercisable for Common Shares, rather than Trust Units, following completion of the 2007 Reorganization. The directors and officers of Fairborne also held an aggregate of 286,379 Restricted Units and 555,675 Performance Units prior to completion of the 2007 Reorganization. While all outstanding Restricted Units and Performance Units vested pursuant to the terms of the Incentive Plan effective immediately prior to completion of 2007 Reorganization, the Non-Vesting Participants waived their right to accelerated vesting of their Restricted Units and Performance Units under the Incentive Plan and, accordingly, such individuals continue to hold in the aggregate 175,711 Restricted Units and 356,275 Performance Units, respectively, which continue to be held subject to the terms and conditions of the Incentive Plan but which are now exercisable for Common Shares, rather than Trust Units, at such times as they become vested.
4. Mr. David E.T. Pyke, an officer of Fairborne, controlled or exercised direction over an aggregate of 12,500 shares of Grand Banks which were exchanged for an aggregate of \$36,250 pursuant to the Grand Banks Acquisition.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of the Corporation are KPMG LLP, Chartered Accountants, Suite 2700, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9.

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, (unless otherwise required by applicable securities requirements to be disclosed), neither Fairborne nor its Subsidiaries have entered into any material contracts within the last financial year, or before the last financial year which are still in effect, other than the Debenture Indenture.

A copy of this document has been filed on SEDAR at www.sedar.com.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than GLJ, the Corporation's independent engineering evaluators and KPMG LLP, the Corporation's auditors. None of the "designated professionals" (as defined in Item 16.2(1.1) of Form 51-102F2 of National Instrument 51-102 of the Canadian Securities Administrators) of GLJ have or are to receive any registered or beneficial interest, direct or indirect, in any of Fairborne's securities or other property of Fairborne or of Fairborne's associates or affiliates, either at the time GLJ prepared the report, valuation, statement or opinion or any time thereafter. KPMG LLP, Chartered Accountants, the Corporation's auditors, are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

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

ADDITIONAL INFORMATION

Additional information including information relating to remuneration and indebtedness of directors and officers of Fairborne, principal holders of Common Shares and securities authorized for issuance under our equity compensation plans, will be contained in the information circular relating to our annual meeting of Shareholders to be held on May 26, 2010. Additional financial information is provided in our comparative financial statements and management discussion and analysis of financial results for the year ended December 31, 2009 which can be found in the Corporation's 2009 Annual Report to Shareholders. Alternatively, additional information relating to us is available on SEDAR at www.sedar.com.

For copies of our information circular, our comparative consolidated financial statements, including any interim consolidated comparative financial statements and additional copies of the Annual Information Form please contact:

Fairborne Energy Ltd.
Suite 3400, 450 - 1st Street S.W.
Calgary, Alberta T2P 5H1
Tel: (403) 290-3217
Fax: (403) 290-7724

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

Management of Fairborne Energy Ltd. ("**Fairborne**") is responsible for the preparation and disclosure of information with respect to Fairborne'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, 2009 estimated using forecast prices and costs.

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

The Reserves Committee of the board of directors of Fairborne has

- (a) reviewed Fairborne'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 of Fairborne has reviewed Fairborne's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has approved

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

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

DATED as of this 3rd day of March, 2010.

(signed) "Steven R. VanSickle"
Steven R. VanSickle
President and Chief Executive Officer

(signed) "Aaron G. Grandberg"
Aaron G. Grandberg
Chief Financial Officer

(signed) "Johannes J. Nieuwenburg"
Johannes J. Nieuwenburg
Lead Director and Chairman of the Reserves Committee

(signed) "Robert B. Hodgins"
Robert B. Hodgins
Director and Member of the Reserves Committee

SCHEDULE "B"
FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Fairborne Energy Ltd. (the "**Company**"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.
2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

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

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.
4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2009, and identifies the respective portions thereof that we have evaluated on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - \$M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants Ltd.	January 28, 2010	Canada	-	\$1,049,513		\$1,049,513

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.
6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.
7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

EXECUTED as to our report referred to above.

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 12, 2010

Per: (signed) "Doug R. Sutton"
 Doug R. Sutton, P.Eng.
 Vice-President

SCHEDULE "C"
MANDATE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Fairborne Energy Ltd. ("**Fairborne**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the following:

1. nature and scope of the annual audit;
2. the oversight of management's reporting on internal accounting standards and practices;
3. the review of financial information, accounting systems and procedures;
4. financial reporting and financial statements,

and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist directors of Fairborne ("**Directors**") in meeting 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 enhance the external auditor's independence;
4. To increase the credibility and objectivity of financial reports; and
5. To strengthen the role of the outside Directors by facilitating in depth discussions between Directors on the Committee, management of Fairborne ("Management") and external auditors.

Membership of Committee

1. The Committee will be comprised of at least three (3) Directors or such greater number as the Board may determine from time to time and all members of the Committee shall be "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("**MI 52-110**") unless the Board determines that the exemption contained in MI 52-110 is available and determines to rely thereon.
2. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.
3. All of the members of the Committee must be "financially literate" (as defined in MI 52-110) unless the Board determines that an exemption under MI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of MI 52-110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

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

2. Satisfy itself on behalf of the Board with respect to Fairborne's internal control systems.
3. Review the annual and interim financial statements of the Corporation and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval. The process should include but not be limited to:
 - reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;
 - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
 - reviewing accounting treatment of unusual or non-recurring transactions;
 - ascertaining compliance with covenants under loan agreements;
 - reviewing disclosure requirements for commitments and contingencies;
 - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
 - reviewing unresolved differences between Management and the external auditors; and
 - obtain explanations of significant variances with comparative reporting periods.
4. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee must be satisfied that adequate procedures are in place for the review of Fairborne's disclosure of all other financial information and will periodically assess the accuracy of those procedures.
5. With respect to the appointment of external auditors by the Board:
 - recommend to the Board the external auditors to be nominated;
 - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
 - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
 - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and
 - review and pre approve any non-audit services to be provided to Fairborne or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may delegate to one or more independent members the authority to pre-approve non-audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre-approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.
6. Review with external auditors (and internal auditor if one is appointed by Fairborne) their assessment of the internal controls of Fairborne, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses. The Committee will also review

annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Fairborne and its subsidiaries.

7. Establish a procedure for:
 - the receipt, retention and treatment of complaints received by Fairborne regarding accounting, internal accounting controls or auditing matters; and
 - the confidential, anonymous submission by employees of Fairborne of concerns regarding questionable accounting or auditing matters.
8. Review and approve Fairborne's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

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

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

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution shall be decided by a majority of the votes cast. In case of an equality of votes, the Chairman of the meeting shall be entitled to a second or casting vote.
2. The Chair will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.
3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board unless otherwise determined by the Committee or the Board.
4. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer of Fairborne will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.
5. The Committee will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.
6. Agendas, approved by the Chair, will be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.
7. The Committee may invite such officers, directors and employees of the Corporation and its subsidiaries as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.
8. Minutes of the Committee will be recorded and maintained and circulated to Directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.
9. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

10. Any members of the Committee may be removed or replaced at any time by the Board and will cease to be a member of the Committee as soon as such member ceases to be a Director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee each member will hold such office until the Committee is reconstituted.
11. Any issues arising from these meetings that bear on the relationship between the Board and Management should be communicated to the Chairman of the Board by the Committee Chair.